STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

DEP File No.0970043-007-AC, PSD-FL-182A
Cane Island Power Park
Osceola County

Enclosed is Final Permit Number 0970043-007-AC. This permit authorizes Kissimmee Utility Authority to continue to operate the Cane Island Power Plant Unit 1 with a 25 ppmvd NO_X emission limit while firing natural gas. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

C. H. Fancy, 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 12-20-99 to the person(s) listed:

A. K. Sharma, Kissimmee Utility Authority *
D.D. Schultz, P.E., Black & Veatch
Timothy M. Hillman, Black & Veatch
Doug Neeley, EPA
John Bunyak, NPS
Len Kozlov, DEP-CD

Clerk Stamp

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

(Clerk) 12-20-99 (Date)

FINAL DETERMINATION

Kissimmee Utility Authority
Cane Island Power Park
DEP File No. 0970043-007-AC, PSD-FL-182A

The Department distributed a public notice package on November 10, 1999 to allow the applicant to modify its permit at the Cane Island Power Park located in Osceola County. The Public Notice of Intent to Issue was published in the Orlando Sentinel on November 19, 1999.

COMMENTS/CHANGES

No comments were received by the Department from the public.

The EPA noted that they had no significant comments. However, the Agency recommended that KUA continue working with the vendor (General Electric) to achieve the NO_X emission rate goal of 15 ppm.

The National Park Service commented, noting that by contrast, Orange Cogen requested that its date for meeting the original 15 ppm target for its GE LM6000PB aeroderivative be deferred until 9/1/01 while GE continues to work on technical improvements. A similar approach was recommended, specifically maintaining the target at 15 ppm but allowing more time to reach the target.

No comments were received from the applicant.

The Department determined that a minor corrections or changes should be made to the draft permit text in an effort to accommodate the above recommendations. The corrections or changes are summarized in the new condition below.

> *Specific Condition 16.(d).:* As it may become available, provide to the Department information regarding documented enhancements to the LM6000PA, duel-fuel class, combustion turbine machine, which have demonstrated in the field the ability to achieve a continuous NO_X emission rate of 15 ppmvd while firing natural gas.

CONCLUSION

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

FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 21, 1999

Mr. A. K. Sharma
Director of Power Supply
KUA –Cane Island Power Park
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Re: DEP File No. 0970043-007-AC; Modification of Permit No. PSD-FL-182A
Cane Island Power Park / Osceola County

The applicant, Kissimmee Utility Authority, applied on September 1, 1999, to the Department for a modification to air construction permit number PSD-FL-182A for its Cane Island Power Park located in Osceola County. The modification is to allow the 40-Megawatt Unit 1 to continue to operate at its permitted NO_X emission rate of 25 ppm, eliminating the requirement to reduce this emission rate to 15 ppm on 1/1/2000. The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

Specific Condition No. 3:

This source is allowed to operate ~~continuously (8760 hours per year)~~ as follows:

1) 40 MW Simple Cycle Turbine – up to 5000 hours per year.

2) 120 MW Combined Cycle Turbine – up to 8760 hours per year.

Specific Condition No. 4:

(deleted and replaced as follows):

The only fuel(s) allowed to be burned are natural gas and number 2 fuel oil (0.05%). The firing of number 2 fuel oil (within the 5000 hour annual limitation) is limited to no more than 1000 hours per year if natural gas is unavailable, or no more than 800 hours per year if gas is available. The sulfur content of the fuel oil shall not exceed 0.05%, by weight.

Specific Condition 15b and Table 1, Note B:

The 40 MW simple cycle unit (LM6000PA) shall achieve a maximum NO_X emission level of ~~15~~25(gas)/42(oil) ppmv ~~by 1/1/2000~~. Emissions units number 1 and 2 are required to comply with an annual NO_X cap of 366.1 tons. In order to comply with this cap, monthly NO_X emissions as recorded by the installed CEMS shall be maintained at the facility. These records shall demonstrate that the cap is complied with during each consecutive 12-month period. Additionally, the annual submittal of each AOR shall include such data and calculations.

Specific Condition 16.(d).:

As it may become available, provide to the Department information regarding documented enhancements to the LM6000PA, duel-fuel class, combustion turbine machine, which have demonstrated in the field the ability to achieve a continuous NO_X emission rate of 15 ppmvd while firing natural gas.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

HN

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-20-99 to the person(s) listed:

A. K. Sharma, Kissimmee Utility Authority *
D.D. Schultz, P.E., Black & Veatch
Timothy M. Hillman, Black & Veatch
Doug Neeley, EPA
John Bunyak, NPS
Len Kozlov, DEP-CD

Clerk Stamp

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

(Clerk) 12-20-99 (Date)

Memorandum **Florida Department of Environmental Protection**

TO: Howard L. Rhodes

FROM: Clair H. Fancy

DATE: December 20, 1999

SUBJECT: FINAL Modification of Permit No.: 0970043-007-AC
Kissimmee Utility Authority
Cane Island Power Park

This permit is for a modification to the air construction permit for the subject facility. The modification allows KUA to continue to operate its 40MW simple cycle Unit 1 at 25 ppmvd NO_X emissions while firing natural gas. The existing permit requires the unit to meet an emission limit of 15 ppmvd effective 1/1/00. Two previous extensions were granted from the original construction permit requirement of 1/1/98. In order to ensure that no net increase of NO_X emissions occurs, KUA will be subject to limited operating hours on Unit 1 and abide by an emissions cap to be shared with Unit 2.

We received no public comments and only minor comments from the USEPA.

The NPS and EPA recommended that KUA continue its efforts to reduce the NO_X emission rate from 25 ppm to 15 ppm. We have attempted to accommodate this issue in the final permit.

I recommend your signature.

Attachment

CHF/aal/mph

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
A.K. Sharma
KUA
1701 W. Carroll St.
Kissimmee, Fl
34641-6804

4a. Article Number
Z 031 392 005

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
11/12/99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Manuel

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

Thank you for using Return Receipt Service.

Z 031 392 005

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	A K Sharma
Street & Number	KUA
Post Office, State, & ZIP Code	Kissimmee Fl
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	11-10-99

PSD-F1-182A
Cane Island PP

PS Form 3800, April 1995

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 10, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: DEP File No. (PSD-FL-182A)
Cane Island Power Park

Dear Mr. Sharma:

Enclosed is one copy of the Draft Air Construction Permit Modification for Cane Island Power Park. This modification relates to changes in permitted levels of Nitrogen Oxide emissions, potential to emit (PTE) emissions, hours of operation and methods of compliance for the Cane Island Units No. 1 and 2 located in Osceola County. The Department's Intent to Issue Air Construction Permit Modification and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit amendment.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A.A. Linero, P.E., New Source Review Section at the above letterhead address. If you have any other questions, please contact Mr. M. P. Halpin, P.E. at 850/921-9530.

Sincerely,

A. A. Linero, P.E.

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

CHF/mph

Enclosures

In the Matter of an
Application for Permit Modification by:

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

DEP File No. 0970043-007-AC
Permit PSD-FL-182A
Cane Island Power Park
Osceola County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit modification (copy of DRAFT Permit modification attached) for the proposed action, as detailed in the application specified above, for the reasons stated below.

The applicant, Kissimmee Utility Authority applied on September 1, 1999, to the Department for an air construction permit modification to revise the permitted NOx emission rate and hours of operation for its simple cycle combustion turbine Unit No. 1, located at the Cane Island Power Park, Osceola County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above action is not exempt from permitting procedures. The Department has determined that an air construction permit modification is required to increase the heat-input limits, megawatt rating and start-up times.

The Department intends to issue this air construction permit modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

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

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

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

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION (including the PUBLIC NOTICE, and DRAFT permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11-10-99 to the person(s) listed:

A. K. Sharma, Kissimmee Utility Authority *
D. D. Schultz, P.E., Black & Veatch
Timothy M. Hillman, Black & Veatch
Doug Neeley, EPA
John Bunyak, NPS
Len Kozlov, DEP-CD

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 11-10-99
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Kissimmee Utility Authority, Cane Island Power Park
DEP File No. PSD-FL-182A, 0970043-007-AC
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue a modification of a Prevention of Significant Deterioration (PSD) Permit to Kissimmee Utility Authority (KUA) for its Cane Island Power Park located in Osceola County. A Best Available Control Technology (BACT) determination was required for this modification pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD). The applicant's name and address are: Kissimmee Utility Authority, 1701 West Carroll Street, Kissimmee, Florida 34741.

This is an existing facility consisting of a 40 Megawatt simple cycle combustion turbine (Unit 1) as well as a 120 Megawatt combined cycle unit (Unit 2). Both units fire natural gas and No. 2 fuel oil with gas/oil heat inputs of 367/372 and 869/928 MMBtu/hr respectively (at an ambient temperature of 59°F). These units have a Title V permit (0970043-001-AV) issued by the State of Florida.

The permitted emission rates of nitrogen oxides (NO_X) for Units 1 and 2 while firing gas/oil are 25/42 ppm and 15/42 respectively. On an annual basis the permitted tons per year (TPY) of potential NO_X emissions are 171.2 and 290.6 respectively. Effective January 1, 2000 the permitted NO_X emission rate for Unit 1 decreases to 15 ppm while firing natural gas firing, causing the potential TPY of NO_X to be equal to 116.9 (a reduction of 54.3 TPY).

KUA requests that the aforementioned NO_X emission rate for Unit 1 remain at 25 ppm while firing natural gas, thereby eliminating the emission rate reduction slated for January 1, 2000. In order to ensure that the potential annual emissions (TPY) of NO_X do not remain at the higher levels, further emission limits are proposed as described below. These emission limits will be accomplished by a reduction in the permitted operating hours of Unit 1 as well as an annual NO_X cap for the combined operation of Units 1 and 2. No other emission limit increases are requested.

	Unit 1 potential NO_X emissions	Unit 2 potential NO_X emissions	Units 1 and 2 combined potential NO_X emissions
As currently permitted	171.2	290.6	461.8
As permitted effective 1/1/00	116.9	290.6	407.5
As requested effective 1/1/00	103.5	290.6	366.1 (annual cap)

In addition to the above, a number of other Unit 1 pollutant emissions have the potential to be reduced. These are itemized below.

Pollutant – Tons per year (TPY)	Permitted Unit 1 Potential Emissions effective 1/1/00	Requested Unit 1 Potential Emissions effective 1/1/00	Unit 1 Potential Emissions Reductions
Particulate Matter (PM/PM10)	40.9	24	16.9
Volatile Organic Compounds (VOC)	6.9	4.3	2.6
Carbon Monoxide (CO)	193.2	121.5	71.7

It is noted that emissions from Unit 1 have ranged from 6 to 29 tons per year of NO_X over a 5 year period. This reflects the peaking characteristics of the Unit. These values are less than significant for PSD and it is expected that the unit will typically operate in a similar manner in the future regardless of potential emissions.

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of "Public Notice of Intent to Issue PSD Permit Modification." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

Department of Environmental Protection
Central District Office
3319 Maguire Blvd., Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the Draft Permit modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

TECHNICAL EVALUATION

PRELIMINARY DETERMINATION

AND

DRAFT REVISED BACT DETERMINATION

Kissimmee Utility Authority

Cane Island Power Park

Cane Island Unit 1

Osceola County

DEP File No. 0970043-007-AC

PSD-FL-182A

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

November 10, 1999

TECHNICAL EVALUATION AND REVISED BACT DETERMINATION

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Cane Island Power Park
Cane Island Unit 1
6075 Old Tampa Hwy
Intercession City, Florida 33848-9999

Authorized Representative: A.K. Sharma, Director of Power Supply

1.2 REVIEWING AND PROCESS SCHEDULE

September 1, 1999	Received permit application and fee
September 24, 1999	Department's request for additional information
October 27, 1999	Received response to request for additional information
October 27, 1999	Application complete

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located at Intercession City, Osceola County. The UTM coordinates are Zone 17; 447.72 km E; 3127.68 km N. This site is approximately 114 kilometers from Chassahowitzka Wildlife Refuge, a Class I PSD Area.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

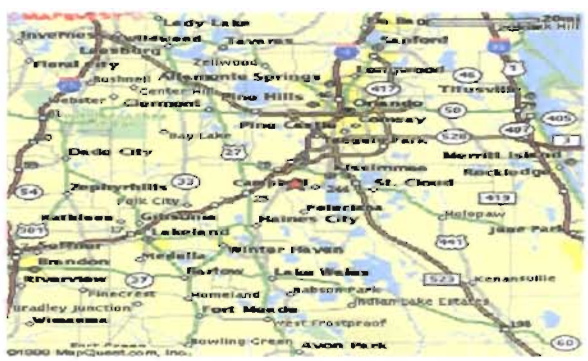
Industry Group No.	49	Electric, Gas and Sanitary Services
Industry No.	4911	Electric Services

2.3 FACILITY CATEGORY

The facility consists of Simple Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 MMBtu/hr for natural gas and 372 MMBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack. Additionally, Combined Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 MMBtu/hr for natural gas and 928 MMBtu/hr for number 2 fuel oil, is capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack.

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). This facility is a major source of hazardous air pollutants (HAPs) and is also subject to the provisions of Title IV, Acid Rain, Clean Air Act. as amended in 1990.



3. PROJECT DESCRIPTION

This project addresses the following emissions unit(s):

Emissions Unit No.	Emissions unit Description
001	GE LM6000PA Simple Cycle Combustion Turbine Unit 1; rated at 40 MW, 367 MMBtu/hr for natural gas and 372 MMBtu/hr for number 2 fuel oil (0.05% S).

The applicant proposes to maintain its current NO_X emission rate of 25 ppmvd while firing natural gas. This emission rate is currently required to be reduced to 15 ppmvd on January 1, 2000. The original BACT and construction permit had required this reduction to occur by January 1, 1998. However, through two separate permit extensions of one year each (the last being 0970043-005-AC), this requirement has been set at January 1, 2000 and is reflected in the Title V permit as a specific requirement. No changes to the permitted NO_X emission rate of 42 ppmvd while firing 0.05% S oil, the permitted emission rate of other pollutants, nor the permitted hours of oil operation are included within the applicant's request.

4. PROJECT EMISSIONS

The following table summarizes the potential maximum emissions increases of nitrogen oxides, comparing past actual to future potential emissions in TPY:

Year	Past Actual	Future Potential	Maximum Emissions Change	PSD Significance Level [1]	Subject to PSD Review?
1998	13.77				
1997	10.55				
1996	5.80				
1995	29.20				
1994	12.94				
5 year average	14.5	171.2*	156.7	40	Yes

* Based upon 25 ppm for 7760 hours/year (gas operation) and 42 ppm for 1000 hours/year (oil operation)

[1] Florida Administrative Code 62-212.400-2.

The proposed project will result in "significant increases" with respect to Table 62-212.400-2, F.A.C., of emissions of 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.

Both Units 1 and 2 have begun normal operations. Yet, it is evident from the historical data, that Unit 1 has not even emitted NO_X at annual rates in excess of 40 tons per year (the significant emission rate). The KUA proposal does not include any physical changes or changes in method of operation that are likely to actually increase utilization of the units. This fact does not exempt the proposal from PSD review because it is necessary to calculate the increases by subtracting past actual emissions from future potential emissions when considering simple cycle units.

Nevertheless a previous reference to the procedure was made in the Puerto Rican Cement Decision. This is the watershed Federal Circuit Court of Appeals decision that upheld the past actual-to-potential emission comparison applicable to (at least) modernization projects. The comments of interest for the purposes of the present review are as follows:

> *"One can imagine circumstances that might test the reasonableness of EPA's regulation. An electricity company, for example, might wish to replace a peak load generator -- one that operates only a few days per year -- with a new peak load generator that the firm could, but almost certainly will not, operate every day. And, uncertainties about the precise shape of future electricity peak demand might make the firm hesitate to promise*

> *EPA it will never increase actual emissions (particularly since EPA insists, as a condition of accepting the promise and issuing the NAD, that the firm also promise not to apply for permission for an actual increase under the PSD review process). Whatever the arguments about the "irrationality" of EPA's interpretation in such circumstances, however, those circumstances are not present here. The Company is not interested in peak load capacity; it operated its old kilns at low levels in the past; its new, more efficient kiln might give it the economic ability to increase production; consequently, EPA could plausibly fear an increase in actual emissions were it to provide the NAD. Thus, this seems the very type of case for which the regulations quoted above were written. We can find nothing arbitrary or irrational about EPA applying those regulations to the Company's proposal."*

KUA's proposal does not replace a unit or modify it in any way. At the same time, KUA is not trying to avoid a BACT determination. However some consideration can be given for their proven status as a peaking unit. They are obviously reluctant, as in the example cited above, to shrink the unit (or the "modification" to a minor source) by an excessively stringent limit on hours of operation.

5. RULE APPLICABILITY

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

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for all pollutants.

Rule 62-4.030, F.A.C., prohibits modification of any existing emissions unit without first receiving a permit. It further specifies that a permitted installation may only be modified in a manner that is consistent with the terms of such a permit. Rule 62-210.200, F.A.C., defines "modification" to mean generally a change that results in an increase in actual emissions of regulated air pollutants. Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C., also reiterate the requirement for construction permits. As noted above, future potential emissions were estimated based on unrestricted operation of the emissions units. The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules.

5.1 STATE REGULATIONS

Chapter 62-4	Permits
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.200	Definitions
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-212.410	Best Available Control Technology (BACT)
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards

5.2 FEDERAL RULES

40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. AIR POLLUTION CONTROL TECHNIQUES

The applicant proposed to control NO_X emissions through a limitation on operating hours. Following is a summary of the available control techniques for this project.

6.1 APPLICANT CONTROL TECHNOLOGY (BACT) PROPOSAL

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED LIMIT
Nitrogen Oxides	Limit hours of operation	5000 hrs/yr (Natural gas at 25 ppmvd) of which up to 1000 hrs may be on #2 oil (at 42 ppmvd)

6.2 STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

The minimum project control technology basis 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 limit required by this subpart is 75 ppmvd NO_X at 15% O2. The BACT proposed by KUA is consistent with the requirements of this subpart. No National Emission Standards for Hazardous Air Pollutants exist for this project.

6.3 NITROGEN OXIDES (NO_X) EMISSIONS

Nitrogen oxides form in the 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 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. Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas because natural gas has little or no fuel nitrogen. It is noteworthy that the LM6000PA aeroderivative machines employ very high compression ratios with correspondingly high flame temperatures. Accordingly, the ability to maintain a NO_X emission rate of less than 25 ppm while firing natural gas has not been demonstrated without the use of SCR (see attached "LM6000 Fleet Emission Data").

Control techniques for NO_X that are applicable to this project are itemized below and form the underpinnings for this BACT Determination:

CONTROL TECHNOLOGY	TECHNICALLY FEASIBLE	ECONOMICALLY FEASIBLE	BACT
Hot SCR	Yes	No - $6,794/ton*	No
GE SPRINT Technology	No - LM6000PC Only	N/A	No
Maximum Water Injection	No; Current Practice – Yields emissions just under 25 ppm	N/A	No

*Note: Based upon 126 TPY reduction (8760 operating hours) and $856,000 annual cost.

6.4 DEPARTMENT BACT DETERMINATION

The Department has determined that no hardware solution is both technically and economically feasible and therefore intends to impose BACT via administrative measures rather than requiring control changes. The table below forms the basis of this determination:

	Unit 1 potential NO_X emissions	Unit 2 potential NO_X emissions	Units 1 and 2 combined potential NO_X emissions
As currently permitted	171.2	290.6	446.0
As currently permitted 1/1/00	116.9	290.6	407.5

The Department notes that KUA Cane Island Number 2 routinely operates below its 15 ppm NO_X limit with something more than an adequate operating margin. Accordingly, it is reasonable that the potential to emit (PTE) for Unit 2 may be adjusted downward to further accommodate the Unit 1 request. In order to make this reduction in a fashion that allows for operational flexibility at the facility, a NO_X cap will be imposed that incorporates both Units 1 and 2. This further reduction is calculated based upon the premise that the Unit 1 operating hours are reduced to 5000 per year (with oil-firing provisions) as requested by KUA, but that the gas-firing hours should be at an emission rate equivalent to 15 ppm rather than 25 ppm. The Department calculates that difference to be equal to 28 TPY. Therefore, the BACT is determined to be:

	Unit 1 potential NO_X emissions	Unit 2 potential NO_X emissions	Units 1 and 2 combined potential NO_X emissions
As currently permitted	171.2	290.6	446.0
As currently permitted 1/1/00	116.9	290.6	407.5
BACT Determination	75.5♠	290.6	366.1

♠ Equivalent limit based upon 4000 hours of gas operation (15 ppm) and 1000 hours of oil operation (42ppm). Unit 1 annual emissions may be as high as 103.5 TPY (28 TPY higher) provided that the combined emissions of 366.1 TPY are not exceeded.

The Department notes that Unit 1 has averaged 14.5 TPY of NO_X emissions, indicating that this BACT Determination authorizes an increase equivalent to 61 TPY (75.5 minus 14.5) which exceeds the PSD significance level by a mere 21 TPY.

In addition to the PTE reductions noted above, placement of the 5000 hours operating limit on Unit 1 causes coincidental decreases of the PTE for other pollutants, most notably a CO reduction of over 70 TPY.

6.5 ADDITIONAL COMPLIANCE PROCEDURES

Pollutant	Compliance Procedure
Unit 1 NO_X (30-day average)	NO_X CEMS data used for compliance with cap
Unit 2 NO_X (30-day average)	NO_X CEMS data used for compliance with cap

The NO_X emissions from these units shall be added together each month and form the basis for the 12 month NO_X cap. A specific permit condition shall describe this calculation.

7. SOURCE IMPACT ANALYSIS

An ambient air quality impact assessment was done in support of the original PSD application dated June 1992. Emissions modeled for that submittal were under the scenarios of 8760 hours per year operation of each fuel (natural gas and 0.3% Sulfur oil). The NO_X emission rates modeled for that assessment were at 25/42 (gas/oil) ppmvd. Since this Determination results in emissions that are less than or equal to the original modeling work, no further modeling is required.

8. CONCLUSION

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

LM6000 Fleet Emission Data

LM6000 Config	Owner	Site Name	Location	Type	Emissions NOx (ppm)
PA-NDW	Energy Initiatives	Lake 2	Umatilla, FL	CC/Cogen	25
PA-NDW	Energy Initiatives	Pasco 2	Dade City, FL	CC/Cogen	25
PA-NDW	Energy Initiatives	Pasco 1	Dade City, FL	CC/Cogen	25
PA-NDW	Energy Initiatives	Lake 1	Umatilla, FL	CC/Cogen	25
PA-NGS	TransAlta	Trans Alta #1	Ottawa, Canada	CC/Cogen	42
PA-NGS	Trans Alta	Trans Alta #GE-101	Mississuaga, Canada	CC/Cogen	42
PA-NDW	US Generating	E Syracuse 1	E. Syracuse, NY	CC/Cogen	
PA-NDW	US Generating	E Syracuse 2	E. Syracuse, NY	CC/Cogen	
PA-NGW	Hutchinson Utilities Comm	City of Hutchinson	Hutchinson, MN	SC/	25
PA-NGS	TransAlta	Trans Alta #GE-102	Mississauga, Canada	CC/Cogen	42
PA-NDW	KIAC Partners -	Kennedy Airport 1	Queens, NY	CC/Cogen	25 (to 42 with water)
PA-NDW	CEA/Brooklyn Union Gas	Kennedy Airport 2	Queens, NY	CC/Cogen	25 (to 42 with water)
PA-NGS	Florida Power Corp	U of Florida	Gainesville, FL	CC/Cogen	25
PA-NDW	Lake Superior	Union Energy #1	Sault St. Marie, Ont	CC/Cogen	Dry
PA-NDW	Northeast Utilities	South Meadow Station	Hartford, Connecticut		
PA-NGW	Lake Superior Power	Union Energy #2	Sault St. Marie, Ont	CC/Cogen	Dry
PA-NGS	Thermo	Ft. Lupton A (lease-107)	Ft. Lupton, CO	CC/Cogen	42
PA-NGW	Las Vegas Cogen, LP	Las Vegas Cogen	Las Vegas, NV	CC/Cogen	60
PA-NGS	Thermo	Ft. Lupton C (lease-138)	Ft. Lupton, CO	CC/Cogen	42
PA-NDW	CEA Nissequogue	SUNY	Stony Brook, NY	CC/Cogen	25
PA-NDW	Cogen Partners of America	Progresso Foods	Vineland, NJ	CC/Cogen	60
PA-NDW	Kissimmee Util. Authority	Kissimmee	Kissimmee, FL	SC	25(gas)/42(liq)
PA-NGS	Thermo	Ft. Lupton B	Ft. Lupton, CO	CC/Cogen	42
PA-NGS	Thermo	Ft. Lupton D	Ft. Lupton, CO	CC/Cogen	42
PA-NGS	Thermo	Ft. Lupton E	Ft. Lupton, CO	CC/Cogen	42
PA-NGW	Kamine/Besicorp Allegany		Hume, NY	CC/Cogen	65 (9 w/ SCR)
PA-NGW		Thermo Monfort			
PA-NDW	Sithe Energies	AG Energy	Ogdensburg, NY	CC/Cogen	75 (9 w/ SCR)
PA-NDW	S.M.U.D.	Carson Energy #1	Elk Grove, CA	CC/Cogen	
PA-NGW	Arroyo Energy	Goal Line Operations	Escondido, CA	CC/Cogen	42 (5 w/SCR)
PA-NGW	S.M.U.D.	Carson Energy #2	Elk Grove, CA	Peaker	
PA-NDW	OMPA	Ponca City Stream Unit #1	Ponca City, Oklahoma		25 (gas)/65(liq)
PA-NDW	Willamette Industries, Inc.	Albany Paper Mill	Albany, Oregon	CC/Cogen	
PA-NGWG03	Northeast Utilities	Devon Station	Connecticut		
PA-NGSG03	Northeast Utilities	Devon Station	Connecticut		
PA-NDW	Potter Power	Potter Power	Tunis, Canada	CC/Cogen	Dry
PA-NGWP06	Northland Power	Iroquois Falls	Iroquois Falls, Canada	CC/Cogen	Dry
PA-NGWP06	Northland Power	Iroquois Falls	Iroquois Falls, Canada	CC/Cogen	Dry
	S.M.U.D	P&G	Sacramento, CA	SC & CC	5 w/SCR
PA-NDWG07	Northeast Utilities	Devon Station	Connecticut		
	Northeast Utilities	Devon Station	Connecticut		
PB-NGD	CSW/ARK 1	Orange Cogen	Bartow, FL	Cogen	25
PB-NGD	CSW/ARK 2	Orange Cogen	Bartow, FL	Cogen	25
PB-NGDG08	TransAlta	Windsor			
PD	Lubbock Power & Light		Lubbock, TX	CC	15 w/SCR
PD	Black Hills Power & Light	Neil Simpson Station II	Wyodak, WY	SC	Proposed -25
PD	Black Hills Power & Light	Lange Combustion Turbine Facility	Rapid City, SD	SC	Proposed -25

December xx, 1999

Mr. A. K. Sharma
Director of Power Supply
KUA –Cane Island Power Park
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Re: DEP File No. 0970043-007-AC; Modification of Permit No. PSD-FL-182A
Cane Island Power Park / Osceola County

The applicant, Kissimmee Utility Authority, applied on September 1, 1999, to the Department for a modification to air construction permit number PSD-FL-182A for its Cane Island Power Park located in Osceola County. The modification is to allow the 40 Megawatt Unit 1 to continue to operate at its permitted NO_X emission rate of 25 ppm, eliminating the requirement to reduce this emission rate to 15 ppm on 1/1/2000. The Department has reviewed the modification request. The referenced permit is hereby modified as follows:

Specific Condition No. 3:

This source is allowed to operate ~~continuously (8760 hours per year)~~ as follows:

1) 40 MW Simple Cycle Turbine – up to 5000 hours per year.
2) 120 MW Combined Cycle Turbine – up to 8760 hours per year.

Specific Condition No. 4:

(deleted and replaced as follows):

The only fuel(s) allowed to be burned are natural gas and number 2 fuel oil (0.05%). The firing of number 2 fuel oil (within the 5000 hour annual limitation) is limited to no more than 1000 hours per year if natural gas is unavailable, or no more than 800 hours per year if gas is available. The sulfur content of the fuel oil shall not exceed 0.05%, by weight.

Specific Condition 15b and Table 1, Note B:

The 40 MW simple cycle unit (LM6000PA) shall achieve a maximum NO_X emission level of ~~15~~25(gas)/42(oil) ppmv ~~by 1/1/2000~~. Emissions units number 1 and 2 are required to comply with an annual NO_X cap of 366.1 tons. In order to comply with this cap, monthly NO_X emissions as recorded by the installed CEMS shall be maintained at the facility. These records shall demonstrate that the cap is complied with during each consecutive 12-month period. Additionally, the annual submittal of each AOR shall include such data and calculations.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on _____________ to the person(s) listed:

A. K. Sharma, Kissimmee Utility Authority *
D.D. Schultz, P.E., Black & Veatch
Timothy M. Hillman, Black & Veatch
Doug Neeley, EPA
John Bunyak, NPS
Len Kozlov, DEP-CD

DRAFT

Clerk Stamp

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

____________________ ______________
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO:	Clair Fancy
THRU:	Al Linero *AL* 11/9
FROM:	Michael P. Halpin *MH*
DATE:	November 9, 1999
SUBJECT:	Kissimmee Utility Authority Cane Island Power Park Modification to NO_X limitation on Unit 1 DEP File No. 097043-007-AC (PSD-FL-182A)

1/1/2000.
Clair - They need finality - I handled for you as obviously we both are extremely busy. Mike discussed approach with EPA who had "no problem" with it. That is not to say they absolutely won't later, but we have good reason to believe it will be ok. 5-year emissions from Unit No. 1 have averaged 14.5 TPY only.
Al

Attached is the public notice package for a modification to the PSD permit for Units 1 and 2 at KUA's Cane Island Power Park. The existing facility is comprised of two units, each of which is permitted to operate 8760 hours. Unit 1 is a 40 MW GE LM6000PA simple cycle aeroderivative combustion turbine-electrical generator. Unit 2 is a nominal 80 MW GE 7EA combustion turbine-electrical generator, with a HRSG and steam turbine-electrical generator capable of producing another 40 MW.

Unit 2 was required to meet a NO_X limit of 15 (gas)/42 (oil) ppmvd. It easily met these values and reportedly achieves between 7 and 10 ppmvd while burning gas. Unit 1 was required to "attempt to achieve a maximum NO_X emission level of 15 (gas)/ 42 (oil) ppmv by 1/1/98." If unable to meet these levels during compliance testing (presumably well before 1/1/98), KUA was required to provide estimated compliance dates and update them on an annual basis. After 1/1/98, the Department "may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation."

Instead of requiring SCR after 1998, the Department inserted a date-certain for compliance with the 15 ppmvd limit when firing gas. The first date was 1/1/99 and it was extended again to 1/1/00. The applicant has determined that no technical solution exists, short of SCR. However they do not want to install SCR and have requested revision of the permit to allow continued operation of Unit 1 at 25 ppmvd while firing gas.

A revised BACT is attached, which evaluates the feasibility of an SCR installation. The applicant's BACT proposal concludes that SCR is not cost effective (>$10,000 per ton) and recommends an annual operating hour limitation (5000 hours per year) which yields annual NO_X emissions equivalent to the lower requirement. GE has advised that there are no further improvements planned for the LM6000PA and they did not guarantee the unit to meet the limits we originally recommended. Our initial recommendation was probably based on an expectation that GE would be able to achieve lower emissions by DLE and the fact that the unit was permitted to operate continuously.

My analysis has also determined that SCR is not cost effective. As mentioned, Unit 2 is routinely emitting NO_X emissions below the permitted rate of 15 ppmv. Accordingly, I am recommending annual PTE reductions (beyond the applicant's proposal) of 28 TPY via a Nitrogen Oxides (NO_X) emissions cap of 366.1 TPY, which includes Units 1 and 2. The NO_X cap referenced in the Draft permit will use CEMS as the compliance tool and require annual reporting. You should be aware that the original PSD application (1992) included modeling for 8760 hours of operation at 25 (gas)/42 (oil). Since I am recommending pollutant emission levels which are less than what was modeled in 1992, I have not required additional modeling.

I recommend your approval of the attached Intent to Issue. Although Day 90 does not occur until 1/24/00, the existing permit (which requires the NO_X reduction) expires on 12/31/99. In order for this Draft permit to be effective on 1/1/00, the Notice will need to be published by 11/17/99.

AAL/mph

Attachments

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

NOV 2 2 1999

4 APT-ARB

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

SUBJ: Preliminary Determination and Draft Permit for Kissimmee Utility Authority (KUA) - Cane Island Power Park Units No. 1 and 2 (PSD-FL-182A) located in Osceola County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft permit dated November 10, 1999, for the above referenced facility. The preliminary determination is for the proposed modification of the permitted levels of nitrogen oxides (NO_x) emissions, potential to emit, hours of operation and method of compliance for the Cane Island Units No. 1 and 2, located in Osceola County, Florida. The existing facility consists of a 40 MW simple cycle combustion turbine (Unit No. 1) and a 120 MW combined cycle combustion turbine (Unit No. 2). The permitted emission rates for NO_x emissions while firing natural gas/fuel oil are 25/42 ppm and 15/42 ppm, respectively. Effective January 1, 2000, the permitted NO_x emission rates for Unit No. 1 will decrease to 15 ppm while firing natural gas. KUA is requesting that the NO_x emission rate while burning natural gas remain at the 25 ppm level, thereby foregoing the planned 54.3 tons per year (TPY) reduction of NO_x emissions. To counteract this increase in potential emissions, KUA is proposing to limit the number of operating hours for both Units No. 1 and 2. The total emissions from the proposed modification are below the thresholds requiring Prevention of Significant Deterioration (PSD) review for NO_x; however, since this is a relaxation of the previous permit terms, this modification is still subject to PSD review.

Based on our review of the preliminary determination and draft permit, we do not have any significant comments. However, we recommend that KUA continue working with the Unit No. 1 combustion turbine vendor (General Electric) to achieve the NO_x emission rate goal of 15 ppm.

If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

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

cc: M. Halpin, BAR
NPS
CD
A.K. Sharma, KUA

The Orlando Sentinel

Osceola County
804 W. Emmett Street
Kissimmee, Florida 34741

Date: Nov 19, 1999

This is to certify that the attached advertisements did publish in The Osceola Sentinel, November 17, 1999.

RECEIVED
NOV 24 1999
BUREAU OF AIR REGULATION

Refik Fortner
Advertising Account Executive
The Osceola Sentinel

STATE OF FLORIDA
COUNTY OF OSCEOLA

I, the undersigned authority, hereby certify that the foregoing is a true and correct copy of the instrument presented to me by Refik Fortner as the original of such instrument.

WITNESS my hand and official seal, this 19th day of Nov., 1999.

STATE OF FLORIDA NOTARY PUBLIC
CYRISE A. FRANEY
My Comm Exp. 1/23/2002
No. CC697517
[ ] Personally Known [ ] Other I.D.

Cyrise A. Franey
Notary Public
State of Florida at Large

My commission expires Jan. 23, 2002.

CC: Halpin, BAR
NPS

CD
EPA

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Kissimmee Utility Authority, Cane Island Power Park
DEP File No. PSD-FL-182A, 0970043-007-AC
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue a modification of a Prevention of Significant Deterioration (PSD) Permit to Kissimmee Utility Authority (KUA) for its Cane Island Power Park located in Osceola County. A Best Available Control Technology (BACT) determination was required for this modification pursuant to Rule 62-212.400, F.A.C. Prevention of Significant Deterioration (PSD). The applicant's name and address are: Kissimmee Utility Authority, 1701 West Carroll Street, Kissimmee, Florida 34741.

This is an existing facility consisting of a 40 Megawatt simple cycle combustion turbine (Unit 1) as well as a 120 Megawatt combined cycle unit (Unit 2). Both units fire natural gas and No. 2 fuel oil with gas/oil heat inputs of 367/372 and 869/928 MMBtu/hr respectively (at an ambient temperature of 59°F). These units have a Title V permit (0970043-001-AV) issued by the State of Florida.

The permitted emission rates of nitrogen oxides (NOx) for Units 1 and 2 while firing gas/oil are 25/42 ppm and 15/42 respectively. On an annual basis the permitted tons per year (TPY) of potential NOx emissions are 171.2 and 290.6 respectively. Effective January 1, 2000 the permitted NOx emission rate for Unit 1 decreases to 15 ppm while firing natural gas firing, causing the potential TPY of NOx to equal to 116.9 (a reduction of 54.3 TPY).

KUA requests that the aforementioned NOx emission rate for Unit 1 remain at 25 ppm while firing natural gas, thereby eliminating the emission rate reduction slated for January 1, 2000. In order to ensure that the potential annual emissions (TPY) of NOx do not remain at the higher levels, further emission limits are proposed as described below. These emission limits will be accomplished by a reduction in the permitted operating hours of Unit 1 as well as an annual NOx cap for the combined operation of Units 1 and 2. No. Other emission limit increases are requested.

	Unit 1 potential NOx emissions	Unit 2 potential NOx emissions	Units 1 and 2 combined potential NOx emissions
As currently permitted	171.2	290.6	461.8
As permitted effective 1/1/00	116.9	290.6	407.5
As requested effective 1/1/00	103.5	290.6	366.1 (annual cap)

In addition to the above, a number of other Unit 1 pollutant emissions have the potential to be reduced. These are itemized below.

Pollutant - Tons per year (TPY)	Permitted Unit 1 Potential Emissions effective 1/1/00	Requested Unit 1 Potential Emissions effective 1/1/00	Unit 1 Potential Emissions Reductions
Particular Matter (PM/PM10)	40.9	24	16.9
Volatile Organic compounds (VOC)	6.9	4.3	2.6
Carbon Monoxide (CO)	193.2	121.5	71.7

It is noted that emissions from Unit 1 have ranged from 6 to 29 tons per year of NOx over a 5 year period. This reflects the peaking characteristics of the Unit. These values are less than significant for PSD and it is expected that the unit will typically operate in a similar manner in the future regardless of potential emissions.

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of "Public Notice of Intent to Issue PSD Permit Modification." Written comments should be provided to the Departments Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

Department of Environmental Protection
Central District Office
3319 Maguire Blvd., Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the Draft Permit modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 851/488-0114, for additional information.

Fold at line over top of envelope to the right of the return address

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. A.K. Sharma
Director of Power Supply
KUA
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

4a. Article Number
P 265 659 306

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
9-27-99

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X Manuel

8. Addressee's Address *(Only if requested and fee is paid)*

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

Thank you for using Return Receipt Service.

P 265 659 306

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to A.K. Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 9-24-99 0970043-007-AC PSD-F1-182A	

PS Form **3800**, April 1995

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

Kissimmee Utility Authority
Cane Island – Unit 1 PSD Permit Amendment Request

B&V Project 24489.018
B&V File 32.0000
October 20, 1999

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Response to Request for Additional Information

Attention: Al Linero
Administrator, New Source Review Section

Gentlemen:

On behalf of Kissimmee Utility Authority (KUA, the Applicant), Black & Veatch (B&V) is herewith submitting the additional information requested in Florida Department of Environmental Protection's (FDEP) September 24, 1999 response to the Applicant's Unit 1 permit amendment application of August 31, 1999. As FDEP is aware, General Electric (GE) has not been able to develop the technology for a dual fuel LM6000PA unit to meet a 15 ppmvd natural gas NOx emission rate, and cannot guarantee when, if ever, such technology may be available. Thus, KUA is requesting an amendment to Construction Permit No. AC49-205703 (PSD-FL-182) and the Initial Title V Air Operating Permit, Permit No. 0970043-002-AV, to modify Unit 1's NOx emission limit during natural gas firing from 15 to 25 ppmvd, based on the revised BACT analysis and an operating limit of 5,000 hours per year. As a result of the requested permit amendment, annual potential emissions from Unit 1 will be less than those currently allowed. FDEP's specific information requests, along with the Applicant's responses, are provided below.

Request Item 1:

What are the lowest levels of NO_X that can possibly be consistently achieved with water injection with the LM6000PA engine, based on the experience of KUA and the engine manufacturer? Are lower emissions achievable with higher water injection rates?

Response:

Historical Unit 1 emission test data and relative accuracy test audit (RATA) data (Attachment A) from 1995 through 1998 indicate that natural gas fired NOx emission levels have ranged from approximately 20 ppmvd @ 15% O_2 to just under 25 ppmvd @ 15% O_2 with water injection. The lowest levels consistently achieved are best represented by recent continuous emissions monitoring (CEM) data from October 12, 1999. These data, included as Attachment B, reveal an average NOx emission level for Unit 1 of 21.4 ppmvd @ 15% O_2 for a 3-hour period on October 12, 1999. The average water-to-fuel injection ratio during this period was 1.03:1.

The water injection control systems for Unit 1 were configured by GE to achieve the delicate balance of minimizing NOx emissions while optimizing turbine performance and limiting CO formation. GE's recommended water-to-fuel ratio for LM6000PC combustion turbines firing natural gas is typically 1.18:1 to achieve NOx levels of 25 ppm, while KUA's experience firing natural gas in the LM6000PA combustion turbine demonstrates that approximately a 1:1 water-to-fuel ratio is necessary to achieve NOx emission levels less than 25 ppm. While higher water-to-fuel ratios may result in limited additional NOx reduction (certainly not down to the 15 ppm level), such ratios are not recommended by GE, and may result in reduced combustor life and increased combustor inspections, increased equipment erosion and maintenance costs, unstable combustor flames and potential flame extinction, and high combustor dynamic pressures. GE does not recommend any higher water injection rates than are necessary to achieve NOx emission levels of 25 ppm. Please refer to GE's letter of October 19, 1999 to KUA regarding this issue (included as Attachment C).

Request Item 2:

Please evaluate the applicability of spray intercooling to reducing NO_X emissions from this engine.

Response:

GE currently offers LM6000PC combustion turbines with spray intercooling technology, also known as SPRINT. There have been several inquiries to GE relative to use of SPRINT technology on LM6000PA combustion turbines, but these have been with an emphasis on providing hot day power augmentation (increasing turbine output on high end days), rather than as a method for enhanced NOx control. To date, SPRINT technology has not been used for emission reductions from a LM6000PA combustion turbine, nor has a decision been made whether GE will consider adapting SPRINT technology for modification of LM6000PA field machines. Please refer to GE's letter of October 19, 1999 included as Attachment C.

Request Item 3:

The analysis provided proposed reducing allowable hours of operation firing gas from the current 8760 hours per year to 5000 hours per year. The application information for potential NO_X emissions shows that KUA proposes no reduction in hours of operation for fuel oil firing, allowing for a total of 6000 hours of operation per year (5000 hours for gas firing plus 1000 hours for oil firing). Based on information provided in annual operation reports, Unit 1 has operated 1096 hours in 1996 and 774 hours in 1997, for an average of 935 hours (firing primarily gas). Comparing past actual operation with proposed future operation shows that NO_X emissions will increase by approximately 105 tons per year. Please address this issue.

Response:

It is the Applicant's position that a hot-side SCR for Unit 1 became cost ineffective in the best available control technology (BACT) analysis when the annual hours of natural gas firing were limited to 5,000 h/yr. Furthermore, it is also ineffective at 8,760 h/yr. Results of the revised BACT analysis submitted with the application were intended to substantiate the requested modification of Unit 1's natural gas NOx emission limit from 15 ppmvd @ 15% O_2 to 25 ppmvd @ 15% O_2 on January 1, 2000. A reduction in fuel oil firing hours is neither relevant to the natural gas NOx limit for Unit 1, as it plays no role in achieving lower gas fired NOx emission limits, nor practical for KUA, who's natural gas fuel contracts and partnership with Florida Municipal Power Agency (FMPA) depend on the level of dual-fuel capability currently allowed.

Test data while firing distillate fuel oil (Included in Attachment A) clearly indicate Unit 1's ability to achieve compliance with the 42 ppmvd @ 15% O_2 NOx emission limit. For these reasons, KUA is not proposing a reduction in the distillate fuel oil firing capability of Unit 1.

A comparison of past actual emissions to future potential emissions is typically performed to determine whether or not a modification (physical change or change in the method of operation of an emission unit) results in a significant emission increase with respect to Prevention of Significant Deterioration (PSD) applicability. It must however be made very clear that KUA is neither proposing a physical modification nor change in the method of operation of Unit 1, but merely a relaxation of the 15 ppm NOx emission limit for natural gas firing scheduled to take effect January 1, 2000. The 15 ppm was based on the specific representations from GE, that GE had emerging technology designed to lower LM6000PA emissions to 15 ppm during natural gas firing. A more accurate and representative comparison of NOx emissions, with regard to the proposed request, is to compare the current permit "Potential Emissions" and future proposed permit "Potential Emissions". The following comparison of "Potentials" to "Potentials" illustrates a 49.7 tpy reduction in NOx emissions from Unit 1 based on an emission limit of 25 ppm and 5,000 h/yr of natural gas operation.

Permitted Emission Levels

(36 lb/h (25ppm) * 7,760 h/yr) + (63 lb/h (42 ppm) * 1,000 h/yr) = 171.2 tpy

Proposed Emission Levels

(36 lb/h (25ppm) * 5,000 h/yr) + (63 lb/h (42 ppm) * 1,000 h/yr) = 121.5 tpy

Additional Emissions Reduction

(171.8 tpy (Permitted Emission Level) – 121.5 tpy (Proposed Emission Level)) = 49.7 tpy

Request Item 4:

The application proposes no reduction in hours for oil firing even though annual operation reports show that the greatest amount of oil firing was in 1998 with approximately 13 full load hours on oil. It appears that KUA could propose a dramatic reduction in allowable hours for oil firing without compromising the ability to operate the unit. Please comment and provide historical data showing the actual hours of operation firing gas and oil as well as the fuel consumption by fuel type for calendar years 1998 through 1994. We wish to confirm the information available in our records from annual operation reports.

Response:

As previously stated in response to Item 3, KUA is currently meeting the permitted fuel oil emission limit of 42 ppm, and does not intend to propose a reduction in allowable hours of fuel oil

Unit 1 – Historical Operating Hours and Fuel Consumption

Year	Fuel	Maximum Documented Operation (h/yr)	Fuel Consumption[a]
1995	Natural Gas Fuel Oil	2,201 2	762.2 Mscf/yr 4,835.4 gal/yr
1996	Natural Gas Fuel Oil	404 1	139.9 Mscf/yr 2,417.7 gal/yr
1997	Natural Gas Fuel Oil	772 2	267.3 Mscf/yr 4,835.4 gal/yr
1998	Natural Gas Fuel Oil	1079 17	373.7 Mscf/yr 41,100.9 gal/yr

[a]The fuel consumption calculations are based on a fuel oil of heat content of 138,064 Btu/gal (HHV) and average fuel oil heat input of 338.8 MBtu/h, and a natural gas heat content of 1,042.5 Btu/scf (HHV) and average heat input of 361.0 MBtu/h.

firing. The fuel oil capability is required for backup capability due to the nature of natural gas and purchase power contracts for both KUA and FMPA. The following table summarizes Unit 1's actual operating hours and fuel consumption as requested.

Request Item 5:

Overall, the control cost effectiveness seems high. The analysis does not appear to have been based upon a vendor's quote for a hot SCR system for this installation; an actual quote should be obtained for this analysis. Below are specific points which appear questionable. The contingency of 25% (particularly on top of a 6% retrofit factor) seems very high given that this is commercially available technology.

A. The contingency of 25% (particularly on top of a 6% retrofit factor) seems very high given that this is commercially available technology.

B. The indirect capital costs were generally calculated as a percentage of the total direct capital cost, although more typically the direct installation costs (in the analysis shown as "balance of plant") are not used to estimate the indirect capital costs.

C. The rate for administrative charges, taxes and insurance at 5.75% is higher than a more typical 4% rate.

D. The nominal interest rate used for the capital recovery factor was 10% (the "real interest rate" shown of 5.5% plus apparently an anticipated annual rate of inflation of 4.5%) although 7% is more typical.

E. The charge for lost power generation from backpressure seems excessive, as does the stated increase in back pressure of 6 inches of water.

F. Catalyst life seems low at 3 years, particularly for a unit that fires primarily gas. The Department is aware of at least one vendor that will guarantee a catalyst life of 3 years inclusive of 1000 hours of annual oil firing, yet no NO_X reductions due to oil firing were included in the analysis.

G. The analysis did not consider the control effectiveness for the allowable use of fuel oil, and did not consider any reduction in annual Title V fees associated with the overall decrease in NO_X emissions from both gas and oil firing.

H. There is no description of what constitutes the "annual distribution check", or justification for this cost.

I. The economic analysis was based on only 5000 hours of operation on gas, although with installation of SCR there would be no reason to limit operation to less than 8760 hours per year.

J. The "starting point" for determining the NO_X reductions appears to presume the continuance of water injection. In the event that an SCR is installed, water injection (for gas as well as oil firing) should be able to be eliminated (or at least reduced). A higher "starting point" should therefore be assumed.

Accounting for these comments would serve to improve the cost effectiveness of SCR. Please provide the basis for costs used in the analysis where they differ from the recommendations in the above comments.

Response:

A quote was not obtained directly for this project. However, B&V had a current quote for a similar project that had been obtained only a month before the cost analysis was being developed for Unit 1. This quote is included as Attachment D along with the calculation performed to adjust this quote to the conditions associated with Unit 1. As illustrated by the costs in the quote, high temperature SCR catalysts are extremely expensive in comparison to conventional SCR catalyst. Changes have been made to the revised BACT cost tables based on FDEP comments. These changes are shown in the enclosed Tables 1 and 2 of Attachment E. It should be noted, however, that these changes do not change the conclusions of the revised BACT analysis which show that installing a high temperature SCR on the Cane Island Unit 1 combustion turbine is not cost effective.

5a. The contingency of 25 percent is typical for studies of this level of detail and is the right level of contingency for this estimate. The contingency accounts for the fact that this is a preliminary design. The following items, which are not resolved at this stage in the project, can significantly impact the cost:

- An exact layout of the new SCR ductwork is not complete
- Location of ammonia storage is not established
- Catalyst prices are in state of fluctuation due to the NOx SIP call being proposed by the EPA for coal fired units
- Structural steel costs are currently volatile
- Labor costs are volatile

Table 3, included in Attachment F shows a comparison of the costs with and without the contingency included. It reasoned from Table 3, that removing the contingency does not result in the high temperature SCR being cost effective.

The six percent retrofit factor is required due to the additional costs associated with retrofit work. The following costs are included in the six percent value:

- Costs associated with lost power generation during the outage to tie in the new equipment.
- Costs associated with additional construction labor required to work around existing equipment at the plant.

5.b. Changes have been made to the costs in accordance with FDEP's comment. Revised costs are reflected in Tables 1 and 2 in Attachment E. Specifically, the Purchase Equipment Cost consists of catalyst and ammonia, ductwork and catalyst reactor, control/instrumentation, and ammonia storage.

5.c. Changes have been made to the costs in accordance with FDEP's comment. Revised costs are reflected in Tables 1 and 2 in Attachment E.

5.d. The capital recovery factor for this project was calculated incorrectly. It should have been based on an interest rate of 5.5 percent. Revisions to the costs using the correct capital recovery factor are shown in Tables 1 and 2 in Attachment E. Please note that this interest rate is less than the seven percent referenced in FDEP's Request for additional information.

5.e. The charge for lost power is based on taking the backpressure on the combustion turbine and converting it to lost kilowatts (kW's). This calculation is based on a graph provided to B&V by Westinghouse on another project. This is the standard calculation used by B&V for calculating lost generation. Once kW's are calculated, the kW's are multiplied by the hours of operation per year and the energy costs (in $/kWh) listed in Table 1 of the revised BACT included in the "Application". The back pressure of 6 inches w.g. was developed by taking the

4.5 in w.g. from the catalyst quote plus an additional 1.5 in w.g. due to the additional ductwork that will be required in Unit 1's retrofit. The extra 1.5 in w.g. would not be required for a new unit.

5.f. The catalyst in the quote has been guaranteed for 3 years worth of operating hours. Therefore, for Unit 1 (with only 5,000 hours of operation), the actual catalyst life is equivalent to 5.3 years. The catalyst costs listed in the revised BACT are for 5.3 years not 3 years. Manufacturers are guaranteeing a catalyst life of three years worth of operating hours. However, there are concerns about how well high temperature SCR's will last on a unit which has the potential to fire fuel oil. Included as Attachment G is a telephone memorandum discussing three oil fired units in Puerto Rico which have rapidly degrading, high temperature SCR catalysts. It should be noted that due to impurities in the oil, fuel oil firing degrades the catalyst even when ammonia is not being injected.

5.g. As previously discussed, no reduction in fuel oil fired emissions are required in this request for modification of the natural gas NOx emission limit and no evaluation of fuel oil NOx reduction is required or relevant to this process. Title V fee savings are not included in the BACT cost analysis, but neither are the training and development costs associated with the Title III - Risk Management Program which are required when ammonia is stored onsite. It is expected that the savings and incurred costs of these two items would nearly offset each other, and therefore were not included in the BACT cost analysis.

5.h. An annual distribution check is required to ensure the ammonia slip is minimized in the SCR system and to track catalyst life. The activities associated with this include NOx testing of the SCR catalyst inlet and outlet. Ammonia testing of the catalyst outlet is included and catalyst activity tests are also included. The costs are based on testing quotes from other projects.

5.i. A revised BACT analysis was performed based on the operating scenario of the Cane Island Power Park. If KUA proposed that Unit 1 would be operated 8,760 hours per year, then the revised BACT analysis would have been performed for 8,760 hours per year. However, we are proposing an operating limitation of 5,000 hours per year. Therefore, this is the operating scenario that should be used to perform the BACT analysis and is the information contained in the revised BACT submitted to FDEP as Attachment D of the "Request Letter".

5.j. As stated in the revised BACT, the analysis follows a "Top Down" approach as USEPA guidance authorizes, and the most stringent NOx control should be compared to the next most stringent NOx control technology analysis. Therefore, an SCR is compared to the next most stringent NOx control (water injection). If the revised BACT had compared SCR to conventional combustors without water injection, it would have skipped an important step in the NOx control alternatives. In addition, the revised BACT analysis would not have followed regulatory guidelines, which require a "Top Down analysis in which the most stringent technology is compared to the next most stringent technology. It seems inconsistent to suggest comparing SCR to conventional combustors when FDEP has a documented history of promoting in-combustion controls over post-combustion controls.

<u>Request Item 6:</u>

Please indicate whether any other (additional) means are available to obtain real offsetting reductions in NO_X emissions from the facility as a whole.

Response:

Short of installing SCR systems, which are clearly contrary to FDEP's documented history of promoting in-combustion controls over post combustion controls, limited annual operation of Unit 1 is the only practical option available to obtain real offsetting NOx reductions.

If you have any questions regarding this submittal, please do not hesitate to call me at 913-458-7928.

Very truly yours,

BLACK & VEATCH

Timothy M. Hillman
Air Permit Coordinator

kjl
Enclosure[s]

cc: Ben Sharma (KUA)
Jeff Ling (KUA)
Tasha Buford

ATTACHMENT A

NOx EMISSION SUMMARY for RELATIVE ACCURACY TEST AUDITS
COMBUSTION TURBINE 1
CANE ISLAND PLANT
KISSIMMEE UTILITIES AUTHORITY
INTERCESSION CITY, FLORIDA
NOVEMBER 15, 1995

FIGURE 1 - RELATIVE ACCURACY DETERMINATION(NOx)

RUN NO.	TIME	NOx PPM @ 15% O2			CT LOAD	NOx LB/MMBTU		
		RM	M	DIFF	MW	RM	M	DIFF
1	0750-0814	22.19	22.39	-0.2	40.0	0.082	0.082	0
2	0837-0901	23.7	22.89	0.81	40.0	0.087	0.084	0.003
3	0909-0933	23.58	23.65	-0.07	40.0	0.087	0.087	0
4	0945-1009	24.32	23.95	0.37	40.0	0.09	0.088	0.002
5	1016-1040	23.94	23.41	0.53	40.0	0.088	0.086	0.002
6	1047-1111	22.99	22.97	0.02	40.0	0.084	0.085	-0.001
7	1121-1145	23.89	23.12	0.77	39.8	0.088	0.085	0.003
8	1152-1216	23.6	23.08	0.52	39.9	0.087	0.085	0.002
9	1224-1248	23.54	23.08	0.46	39.7	0.086	0.085	0.001
TOTAL DATA POINTS:				9				9
AVERAGE :		23.53	23.17	0.357		0.0866	0.0852	0.0013
Sd:				0.362				0.0014
CC:				0.278				0.0011
RA:				2.70				2.80
BAF(BIAS ADJUSTMENT):				1.015				1.016

Table 1 Emission Summary
Units 1 and 2
Cane Island Facility
Kissimmee Utility Authority
Intercession City, Florida
October 8-9, 1996

Unit 1 - Number 2 Diesel Firing - October 9, 1996

Run No.	Time	GPM	Actual Heat Input MMBTUH HHV	O2%	NOx Emissions ppmvd	15% O2 ppmvd	ISO ppmvd	lbs/MMBTU	l
1	0952-1059	38.1	315.61	14.92	38.12	37.59	44.47	0.147	4
2	1122-1231	38.7	320.6	14.65	38.71	36.55	44.19	0.142	4
3	1245-1352	44.1	365.3	14.92	37.99	37.49	46.00	0.146	5
Average		40.3	333.8	14.83	38.27	37.21	44.89	0.145	4

Unit 1 - Natural Gas Firing - October 9, 1996

Run No.	Time	Actual Heat Input KSCFH	MMBTUH HHV	O2%	NOx Emissions ppmvd	15% O2 ppmvd	ISO ppmvd	lbs/MMBTU	ll
1	1458-1648	339.85	354.3	15.41	22.82	24.5	29.97	0.090	3
2	1701-1845	339.85	354.3	15.33	23.02	24.39	29.18	0.090	3
3	1857-2024	359.04	374.3	15.39	23.06	24.68	30.46	0.091	3
Average		346.25	361.0	15.38	22.97	24.52	29.87	0.090	3

Unit 2 - Natural Gas Firing - October 8, 1996

Run No.	Time	Actual Heat Input KSCFH	MMBTUH HHV	O2%	NOx Emissions ppmvd	15% O2 ppmvd	ISO ppmvd	lbs/MMBTU	lb
1	1405-1512	800	834	15.08	7.89	7.99	10.02	0.030	24
2	1532-1639	810	844	15.01	7.91	7.93	10.04	0.029	24
3	1653-1800	815	850	15.12	8.06	8.23	9.90	0.030	25
Average		808	843	15.07	7.95	8.05	9.99	0.030	24

NOTES: ISO = emissions at 59°F, 40% RH, 29.92" Hg
HHV Oil = 138064 BTU/Gal
HHV Gas = 1042.5 BTU/SCF

$$\text{lbs/MMBTU} = \text{ppm}\,(2.595 \times 10\text{-}9)(M)(Fd)\left(\frac{20.9}{20.9 - \%O2}\right)$$

lbs/Hr = lbs/MMBTU x MMBTUH

TABLE 1 - NOx RATA RESULTS
COMBUSTION TURBINE CT-1
KISSIMMEE UTILITIES AUTHORITY
CANE ISLAND PLANT
10/16/97
NATURAL GAS FIRING

RELATIVE ACCURACY DETERMINATION(NOx/DILUENT)

RUN NO.	TIME	REFERENCE METHOD			NOx COMBINED SYSTEM(LB/MMbtu)		
		NOx PPM	O2 %	LB/MMbtu	RM	M	DIFF
1	1007-1037	22.61	15.27	0.087	0.087	0.077	0.010
2	1047-1117	21.15	15.24	0.081	0.081	0.074	0.007
3	1132-1202	20.89	15.23	0.080	0.080	0.074	0.006
4	1210-1240	21.19	15.22	0.081	0.081	0.075	0.006
5	1253-1323	21.50	15.24	0.083	0.083	0.077	0.006
6	1331-1401	22.36	15.23	0.086	0.086	0.076	0.010
7	1410-1434	22.87	15.32	0.089	0.089	0.077	0.012
8	1441-1505	21.82	15.25	0.084	0.084	0.078	0.006
9	1514-1538	21.58	15.17	0.082	0.082	0.077	0.005
TOTAL DATA POINTS:				9			9
AVERAGE DIFF. :		21.78	15.24	0.084	0.084	0.076	0.008
Sd:							0.002
CC:							0.002
RA:							11.29
BAF(BIAS ADJUSTMENT):							1.099

TABLE 1 - NOx RATA RESULTS
COMBUSTION TURBINE CT-1
KISSIMMEE UTILITIES AUTHORITY-CANE ISLAND
INTERCESSION CITY, FLORIDA
10/6/98
NATURAL GAS FIRING

RELATIVE ACCURACY DETERMINATION(NOx/DILUENT)

RUN NO.	TIME	REFERENCE METHOD			NOx COMBINED SYSTEM(LB/MMbtu)		
		NOx PPM	O2 %	LB/MMbtu	RM	M	DIFF
1	1025-1045	21.53	14.64	0.075	0.075	0.079	-0.004
2	1059-1119	20.33	14.75	0.072	0.072	0.081	-0.009
3	1130-1150	19.90	14.69	0.070	0.070	0.082	-0.012
4	1205-1225	22.02	14.71	0.077	0.077	0.083	-0.006
5	1235-1255	20.82	14.72	0.073	0.073	0.083	-0.010
6	1309-1329	20.30	14.77	0.072	0.072	0.083	-0.011
7	1346-1406	21.71	14.76	0.077	0.077	0.083	-0.006
8	1418-1438	21.65	14.70	0.076	0.076	0.083	-0.007
9	1448-1508	22.20	14.71	0.078	0.078	0.083	-0.005
TOTAL DATA POINTS:				9			9
AVERAGE DIFF. :		21.16	14.72	0.074	0.074	0.082	-0.008
Sd:							0.003
CC:			PASSED WITH AVERAGE DIFFERENCE < 0.01				0.002
RA:							13.36
BAF(BIAS ADJUSTMENT):							1.000

ATTACHMENT B

October 12,1999
Unit 1

	NOx_cor_1	H2O_INJ_1	GAS_FL_1	LOAD_1	Gas pph	H2o pph	water to gas ratio
16:30	21.7	27.44	5228	30	14220.9212	13730.976	0.965547577
16:31	21.5	27.39	5219	30.01	14196.43989	13705.956	0.965450219
16:32	24.3	27.55	5218	30.01	14193.71974	13786.02	0.971276047
16:33	20.9	27.63	5224	30.06	14210.04061	13826.052	0.972977655
16:34	21.2	27.83	5223	30.02	14207.32047	13926.132	0.980208198
16:35	21	27.79	5227	30.01	14218.20105	13906.116	0.978050314
16:36	20.9	27.45	5225	30.01	14212.76076	13735.98	0.966454036
16:37	21.4	28.04	5220	30.03	14199.16003	14031.216	0.988172256
16:38	20.9	27.54	5216	30.04	14188.27945	13781.016	0.971295783
16:39	21.2	27.68	5230	30.01	14226.36149	13851.072	0.973620136
16:40	21.1	28.11	5222	30.06	14204.60032	14066.244	0.990259752
16:41	20.8	27.71	5224	30.01	14210.04061	13866.084	0.975794818
16:42	21.2	27.91	5223	30	14207.32047	13966.164	0.983025901
16:43	20.7	30.36	5610	33.09	15260.01682	15192.144	0.995552245
16:44	22.9	32.81	5781	33.94	15725.16171	16418.124	1.044067101
16:45	20.9	31.94	5785	33.89	15736.0423	15982.776	1.015679527
16:46	21.9	32.35	5778	33.81	15717.00128	16187.94	1.02996365
16:47	21.1	32.24	5775	33.84	15708.84084	16132.896	1.026994682
16:48	21.5	32	5778	33.84	15717.00128	16012.8	1.018820303
16:49	21.6	32.45	5782	33.85	15727.88186	16237.98	1.03243273
16:50	21.1	32.1	5774	33.88	15706.12069	16062.84	1.02271212
16:51	21.5	32.64	5779	34.02	15719.72142	16333.056	1.039016886
16:52	21.2	32.21	5785	34.05	15736.0423	16117.884	1.024265422
16:53	21.5	32.77	5777	33.99	15714.28113	16398.108	1.043516268
16:54	21.1	31.82	5762	33.86	15673.47895	15922.728	1.015902599
16:55	21.9	32.6	5766	33.8	15684.35953	16313.04	1.040083273
16:56	21	32.04	5764	33.81	15678.91924	16032.816	1.022571502
16:57	21.4	32.13	5779	33.86	15719.72142	16077.852	1.022782247
16:58	21.5	32.31	5768	33.81	15689.79982	16167.924	1.030473568
16:59	21.4	32.32	5777	33.89	15714.28113	16172.928	1.029186627
17:00	21.4	32.49	5778	33.94	15717.00128	16257.996	1.034420989
17:01	21.4	32.41	5775	33.89	15708.84084	16217.964	1.032409976
17:02	51.8	32.95	5773	33.92	15703.40055	16488.18	1.049975128
17:03	20.2	33	5774	33.88	15706.12069	16513.2	1.051386292
17:04	20.5	32.16	5775	33.89	15708.84084	16092.864	1.024446308
17:05	21.3	32.69	5773	33.93	15703.40055	16358.076	1.041690043
17:06	20.9	32.58	5770	33.94	15695.24011	16303.032	1.0387246
17:07	21.3	32.38	5775	33.85	15708.84084	16202.952	1.031454336
17:08	21.1	32.33	5744	33.75	15624.51633	16177.932	1.0354197
17:09	21.1	32.23	5767	33.84	15687.07968	16127.892	1.028100343
17:10	21.3	32.41	5770	33.78	15695.24011	16217.964	1.033304612
17:11	21.1	32.04	5734	33.76	15597.31487	16032.816	1.027921545
17:12	21.4	32.68	5741	33.77	15616.35589	16353.072	1.04717593
17:13	20.7	32.31	5746	33.72	15629.95662	16167.924	1.034418994
17:14	21	32.3	5740	33.71	15613.63574	16162.92	1.035179779
17:15	21	31.95	5736	33.7	15602.75516	15987.78	1.024676721
17:16	21.2	32.41	5725	33.7	15572.83356	16217.964	1.041426657
17:17	20.8	32.55	5747	33.77	15632.67676	16288.02	1.041921371
17:18	20.8	32.15	5754	33.91	15651.71778	16087.86	1.027865454
17:19	21.5	32.91	5758	33.92	15662.59836	16468.164	1.051432439

17:20	20.6	32.68	5773	33.92	15703.40055	16353.072	1.041371386
17:21	20.8	32.51	5757	33.84	15659.87822	16268.004	1.038833366
17:22	21	32.34	5758	33.76	15662.59836	16182.936	1.033221668
17:23	21.1	32.06	5721	33.66	15561.95298	16042.824	1.030900429
17:24	21	32.09	5714	33.58	15542.91196	16057.836	1.033129187
17:25	21.1	31.94	5714	33.55	15542.91196	15982.776	1.028299976
17:26	21	32.12	5713	33.52	15540.19181	16072.848	1.034276037
17:27	20.9	32.12	5721	33.61	15561.95298	16072.848	1.03282975
17:28	21	32.45	5740	33.77	15613.63574	16237.98	1.039987116
17:29	20.8	32.4	5756	33.76	15657.15807	16212.96	1.035498264
17:30	20.9	32.52	5751	33.77	15643.55735	16273.008	1.040237054
17:31	21	32.16	5759	33.77	15665.31851	16092.864	1.027292486
17:32	33.1	31.74	5735	33.74	15600.03502	15882.696	1.018119253
17:33	21.4	31.77	5749	33.7	15638.11705	15897.708	1.016599885
17:34	21.4	32.23	5753	33.79	15648.99764	16127.892	1.030602239
17:35	20.9	32.1	5761	33.92	15670.7588	16062.84	1.025019924
17:36	21.7	32.48	5773	33.95	15703.40055	16252.992	1.034998244
17:37	21.1	32.41	5778	33.97	15717.00128	16217.964	1.031873938
17:38	21.3	32.11	5775	33.91	15708.84084	16067.844	1.022853574
17:39	21.5	32.4	5776	33.93	15711.56099	16212.96	1.031912743
17:40	21.3	32.56	5782	33.97	15727.88186	16293.024	1.035932502
17:41	21.1	32.22	5784	33.96	15733.32215	16122.888	1.024760559
17:42	21.6	31.92	5775	33.83	15708.84084	15972.768	1.016801186
17:43	21.4	32.06	5757	33.78	15659.87822	16042.824	1.024453944
17:44	21.4	32.18	5774	33.81	15706.12069	16102.872	1.025260936
17:45	21.2	32.19	5766	33.8	15684.35953	16107.876	1.027002471
17:46	21.3	32.17	5757	33.77	15659.87822	16097.868	1.027968914
17:47	21.2	32.21	5770	33.87	15695.24011	16117.884	1.026928157
17:48	21.4	32.42	5784	33.92	15733.32215	16222.968	1.03112158
17:49	21.3	32.67	5790	33.89	15749.64302	16348.068	1.037996098
17:50	20.9	32.02	5753	33.9	15648.99764	16022.808	1.023887176
17:51	21.2	32.47	5761	33.83	15670.7588	16247.988	1.036834796
17:52	21	32.23	5757	33.9	15659.87822	16127.892	1.02988617
17:53	21.2	32.62	5793	33.95	15757.80346	16323.048	1.03587077
17:54	20.9	32.3	5778	33.97	15717.00128	16162.92	1.028371743
17:55	21.3	32.56	5801	33.99	15779.56463	16293.024	1.032539515
17:56	21.1	32.77	5796	33.99	15765.9639	16398.108	1.040095493
17:57	20.8	32.08	5787	33.93	15741.48259	16052.832	1.019778913
17:58	21.3	32.68	5786	33.88	15738.76244	16353.072	1.03903163
17:59	20.7	31.76	5759	33.79	15665.31851	15892.704	1.014515216
18:00	21.3	32.51	5760	33.8	15668.03866	16268.004	1.038292307
18:01	20.7	32.22	5776	33.82	15711.56099	16122.888	1.026179895
18:02	45.4	32.08	5759	33.81	15665.31851	16052.832	1.024737032
18:03	20.5	31.92	5754	33.75	15651.71778	15972.768	1.020512139
18:04	20.6	32.56	5758	33.76	15662.59836	16293.024	1.040250386
18:05	20.3	32.74	5764	33.91	15678.91924	16383.096	1.044912328
18:06	20.5	32.52	5766	33.85	15684.35953	16273.008	1.037530922
18:07	20.4	32.55	5764	33.79	15678.91924	16288.02	1.03884839
18:08	20.5	32.79	5772	33.79	15700.6804	16408.116	1.045057639
18:09	20.4	32.61	5772	33.94	15700.6804	16318.044	1.039320818
18:10	20.5	32.82	5776	33.96	15711.56099	16423.128	1.04528939
18:11	20.6	32.52	5776	33.87	15711.56099	16273.008	1.035734642
18:12	20.9	32.62	5783	33.95	15730.602	16323.048	1.037662004
18:13	20.6	32.65	5791	33.97	15752.36317	16338.06	1.037181522
18:14	20.7	32.43	5792	34.06	15755.08332	16227.972	1.030014991
18:15	20.9	32.8	5797	34.04	15768.68404	16413.12	1.040868087

18:16	20.7	32.53	5764	33.95	15678.91924	16278.012	1.03821008
18:17	20.6	32.68	5765	33.87	15681.63938	16353.072	1.042816481
18:18	20.5	32.06	5776	33.97	15711.56099	16042.824	1.021084029
18:19	21	32.6	5783	34.03	15730.602	16313.04	1.037025792
18:20	20.6	32.5	5787	34.08	15741.48259	16263	1.033130133
18:21	20.8	32.71	5819	34.17	15828.52725	16368.084	1.034087616
18:22	20.9	32.5	5810	34.17	15804.04594	16263	1.029040289
18:23	21	32.65	5800	34.17	15776.84448	16338.06	1.035572102
18:24	21	32.74	5811	34.13	15806.76608	16383.096	1.036460963
18:25	21	32.41	5796	34.07	15765.9639	16217.964	1.02866936
18:26	21	32.44	5795	34.01	15763.24375	16232.976	1.029799212
18:27	21.1	32.47	5787	33.97	15741.48259	16247.988	1.032176474
18:28	21	32.76	5795	34.06	15763.24375	16393.104	1.039957528
18:29	20.7	32.55	5794	34.06	15760.52361	16288.02	1.033469471
18:30	20.8	32.8	5798	34.15	15771.40419	16413.12	1.040688565
18:31	20.9	32.87	5814	34.19	15814.92652	16448.148	1.040039483
18:32	4.7	33.01	5807	34.21	15795.8855	16518.204	1.045728269
18:33	17.5	33.17	5809	34.2	15801.32579	16598.268	1.050435148
18:34	20.2	32.28	5821	34.26	15833.96754	16152.912	1.020143054
18:35	21.3	32.66	5822	34.27	15836.68768	16343.064	1.031974888
18:36	20.9	32.71	5822	34.24	15836.68768	16368.084	1.033554764
18:37	21	32.48	5807	34.24	15795.8855	16252.992	1.028938327
18:38	21.3	32.89	5840	34.26	15885.6503	16458.156	1.036039173
18:39	20.8	32.87	5817	34.26	15823.08696	16448.148	1.039503104
18:40	21.1	32.63	5810	34.21	15804.04594	16328.052	1.03315645
18:41	21.2	32.71	5813	34.32	15812.20637	16368.084	1.035154969
18:42	21.4	32.99	5839	34.3	15882.93016	16508.196	1.039367159
18:43	21.1	32.76	5835	34.33	15872.04958	16393.104	1.032828427
18:44	21.2	33.03	5815	34.25	15817.64666	16528.212	1.044922317
18:45	21	33.13	5816	34.24	15820.36681	16578.252	1.047905665
18:46	20.9	32.67	5818	34.23	15825.8071	16348.068	1.033000585
18:47	21.3	32.5	5820	34.27	15831.24739	16263	1.027272179
18:48	21.4	32.78	5823	34.28	15839.40783	16403.112	1.035588715
18:49	21.4	32.68	5826	34.23	15847.56827	16353.072	1.031897874
18:50	21.4	32.6	5825	34.28	15844.84812	16313.04	1.029548524
18:51	21.4	32.77	5821	34.27	15833.96754	16398.108	1.035628497
18:52	21.3	32.8	5834	34.26	15869.32943	16413.12	1.034266764
18:53	21.4	32.68	5820	34.27	15831.24739	16353.072	1.032961686
18:54	20.8	32.35	5825	34.21	15844.84812	16187.94	1.021653214
18:55	21.1	32.67	5822	34.25	15836.68768	16348.068	1.032290863
18:56	20.8	32.49	5818	34.21	15825.8071	16257.996	1.027309122
18:57	21	32.6	5822	34.24	15836.68768	16313.04	1.030079037
18:58	20.8	32.55	5813	34.24	15812.20637	16288.02	1.030091539
18:59	21.1	32.55	5809	34.26	15801.32579	16288.02	1.030800846
19:00	20.9	32.65	5825	34.29	15844.84812	16338.06	1.031127586
19:01	20.9	32.24	5813	34.3	15812.20637	16132.896	1.020281144
19:02	50.9	32.53	5812	34.29	15809.48623	16278.012	1.029635737
19:03	20.8	32.63	5814	34.34	15814.92652	16328.052	1.032445644
19:04	20.9	32.06	5829	34.37	15855.7287	16042.824	1.011799855
19:05	21.5	32.49	5825	34.33	15844.84812	16257.996	1.026074588
19:06	21.1	32.27	5825	34.26	15844.84812	16147.908	1.019126714
19:07	21.2	32.6	5816	34.31	15820.36681	16313.04	1.031141705
19:08	20.9	32.16	5829	34.31	15855.7287	16092.864	1.014955812
19:09	21.3	32.46	5831	34.29	15861.16899	16242.984	1.024072312
19:10	21.2	32.76	5830	34.32	15858.44885	16393.104	1.033714215
19:11	21	32.27	5843	34.43	15893.81074	16147.908	1.015987183

19:12	22.1	32.93	5861	34.46	15942.77336	16478.172	1.033582528
19:13	21.5	32.93	5859	34.48	15937.33307	16478.172	1.033935347
19:14	21.8	32.67	5865	34.49	15953.65394	16348.068	1.02472249
19:15	21.9	33.11	5862	34.49	15945.49351	16568.244	1.039054953
19:16	21.5	32.66	5861	34.47	15942.77336	16343.064	1.025107968
19:17	21.3	32.93	5844	34.37	15896.53089	16478.172	1.036589185
19:18	21.1	32.19	5847	34.42	15904.69132	16107.876	1.012775141
19:19	21.9	32.92	5852	34.46	15918.29205	16473.168	1.034857757
19:20	21	32.74	5859	34.54	15937.33307	16383.096	1.027969732
19:21	21.2	32.94	5874	34.57	15978.13525	16483.176	1.031608241
19:22	21.1	32.63	5861	34.49	15942.77336	16328.052	1.02416635
19:23	21.2	33.06	5860	34.47	15940.05322	16543.224	1.037839948
19:24	20.9	32.47	5852	34.4	15918.29205	16247.988	1.020711767
19:25	21.5	32.94	5857	34.4	15931.89278	16483.176	1.034602494
19:26	20.9	32.42	5855	34.38	15926.45249	16222.968	1.0186178
19:27	21.4	32.76	5852	34.41	15918.29205	16393.104	1.029828071
19:28	21.1	32.71	5849	34.45	15910.13161	16368.084	1.028783696
19:29	21.1	32.73	5850	34.4	15912.85176	16378.092	1.029236761
19:30	21.1	32.94	5845	34.42	15899.25103	16483.176	1.036726571
19:31	21	32.72	5850	34.51	15912.85176	16373.088	1.028922298
19:32	1.7	32.49	5863	34.56	15948.21365	16257.996	1.019424266
19:33	21.2	32.53	5878	34.66	15989.01584	16278.012	1.018074669
19:34	21.4	32.84	5873	34.6	15975.41511	16433.136	1.02865158
19:35	21.1	32.73	5868	34.52	15961.81438	16378.092	1.026079593

	NOx ppm			Load (MW)	Gas Usage (lb/h)	Water Usage (lb/h)	Water-to-Fuel
1	21.43	32.15	5753.08	33.77	15649.22	16086.89	1.03

Note

1 Including all data

ATTACHMENT C

GE Industrial AeroDerivative
Gas Turbines

GE Power Systems.
One Neumann Way, S158
Cincinnati, OH 45215-1988
Phone: (513) 552-5925
Fax: (513) 552-5059

October 19, 1999

KUA

Attn: Larry Mattern

The purpose of this letter is to

- Respond to your inquiry regarding high water injection rates
- Provide response on the use of spray intercooling on the KUA units

High Water Injection Rates

GE currently offers LM6000PC with water injection for NOx abatement to levels of 25 ppm NOx. At ISO conditions, the expected water : fuel ratio for a typical natural gas fuel is 1.18. With engine-to-engine variation, the water : fuel requirements can be as high as 1.42 to achieve this NOx level.

GE recommends that water should not be injected beyond that required to achieve 25 ppm NOx, and, in no case, beyond 1.42 water to fuel ratio (without consulting GE). Attempts to oversuppress to levels significantly below 25 ppm will have the following consequences and added risks:

- Reduced combustor venturi life and need for more frequent inspections. Expected venturi life is 25000 hours on natural gas with water suppression to 42 ppm. Expected life of the same combustor is 16000 hours at 25 ppm. Erosion life is believed to be very non linear, therefore suppressing to <<25 will result in significantly lower erosion life and increased maintenance costs and reduced availability.
- Oversuppressing *will add risk* in terms of combustor stability and could cause high combustor dynamic pressures which will result in distress of combustion system components.

High Water Injection Rates

GE currently offers spray intercooling, also known as SPRINT™, exclusively on the LM6000PC. While there have been several inquiries relative to use of SPRINT™ with LM6000PA, GE does not currently plan to offer this as a product.

GE recently proposed to the FL-DEP that SPRINT™ could be used in conjunction with other new features on two LM6000 PB engines in Bartow FL in order to achieve the permit level of 15 ppm. This will require a development program and engine testing to ensure no adverse consequences result from the water injection levels envisioned for the LM6000PB machines. If the FL-DEP is supportive of this approach we will be conducting tests before end of June 2000 and will have a better idea of the exact benefits on a PB engine.

The intent of the above program is to achieve 15 ppm on the existing LM6000PB engines at the Bartow site. Since the LM6000PB is no longer in production, this system is not intended to be a general product offering at this time.

Best regards,

RB Hook
LM6000 Technical Program Mgr.
GE Industrial Aeroderivative Gas Turbines

Cc: Z Biernacki, D Harmon, C Stump, P Tinne

ATTACHMENT D

GIVEN

Reference 1 - Quote from Engelhard for high temperature SCR to reduce emissions from an LM 6000. Emissions reduction from 22 ppm to 2 ppm.
Reference 4 - Quote from Cormetech for conventional catalyst. Used as a basis for adjusting costs to Cane Island Unit 1 emissions requirements.

CALCULATING AN ADJUSTMENT FACTOR TO BE USED TO ADJUST ENGELHARD QUOTE

Cormatech Data	inlet	outlet	Price	% Removed	(Reference 4)
RATIO 1 (Case 2) for 25 to 4.5 ppm	25	4.5	$504,000	82%	
RATIO 2 (Case 4) for 9 to 2 ppm	25	2	$737,000	92%	

Therefore, to go from 25 TO 4.5 PPM, requires 68 % of the catalyst for reduction from 25 TO 2.0 PPM
68 % = $504000 / $737000 * 100

ADJUSTING ENGELHARD QUOTE

Engelhard Data	inlet	outlet	Price	(Reference 1)
	22	2.5	$1,558,000	

Therefore, 68 % of $1558000 is the catalyst cost = $1,065,444

Plus, need to correct for the difference in inlet NOx.
A unit achieving 92 % (25 to 2) requires 104 % more catalyst than a unit achieving 89 % (22 to 2.5).
104 % = 92 % / 89 % * 100
Therefore, $1065444 * 104 % is the catalyst cost = $1,105,876

BEST AVAILABLE COPY

Reference 4

p-622-bv-9/16/98

CORMETECH, INC.

ENVIRONMENTAL TECHNOLOGIES

5000 International Drive Durham, NC 27712

TEL 919-620-3000 FAX 919-620-3001

If not received properly, call 919-620-3000

Number of pages including cover: 7 Reference Number: 98 1267

TO:	Rick Lausman BLACK & VEATCH Overland Park, KS 7528 P461	TEL 913-458-7528 FAX 913-458-2934
CC:	Nancy Stephenson	
FROM:	Elizabeth Mancini	
DATE:	9/16/98	
SUBJECT:	SCR Catalyst Budgetary Quotation General Information	
REFERENCE:	1. Cormetech Reference Number CM622 2. Fax from Rick Lausman/BV to Elizabeth Mancini/Cormetech 9/10/98	

We are pleased to submit our budgetary quotation to supply SCR catalyst for the above subject project. Budgetary indicates ± 10%. If you have any questions or require additional information, please contact me at 919-620-3022.

Best regards,

EMa

Fax to Rick Lausman/BV from Elizabeth Mancini/Cormetech
RE: SCR Catalyst Budgetary Quotation: General Information

Scope of Supply:

- Catalyst Design, Supply, and Assembly
- Patent and License Indemnification
- Module Engineering and Supply
- Initial Pilot Test
- Sample Module for Easy Catalyst Sample Retrieval

Catalyst:

	Case 1
Catalyst	CM-27™
Pitch, mm	2.7
Gas Flow Orientation	Horizontal

Modules:

	Case 1	Case 2	Case 3	Case 4
Number/Unit	24	24	24	24
Number of Layers	1	1	1	1
Arrangement/Layer	$3_w \times 8_h$	$3_w \times 8_h$	$3_w \times 8_h$	$3_w \times 8_h$
Dimensions, in each	$127.375_w \times 66.375_h \times 16_d$	$103.125_w \times 66.375_h \times 14_d$	$127.375_w \times 66.375_h \times 16_d$	$127.375_w \times 66.375_h \times 20_d$
Weight, lbs each	2400	1800	2400	2900
Material	Carbon Steel	Carbon Steel	Carbon Steel	Carbon Steel

Price:

	Case 1	Case 2	Case 3	Case 4
Price, 1 Unit(s)	$304,000	$200,000	$313,000	$433,000
FOB	Durham			
Delivery	6 - 9 mo ARO			
Validity from date of this proposal	90 days			
Payment Terms	Net 30 days			
Invoice Schedule	30% upon Order; 70% upon Delivery			
[illegible] %	67.5	53.1	68.8%	79.2%

NO_x [illegible]

CORMETECH CONFIDENTIAL

Fax to Rick Lausman/BV from Elizabeth Mancini/Cormetech
RE: SCR Catalyst Budgetary Quotation: General Information

Guarantee Performance*:

	Case 1	Case 2	Case 3	Case 4
NOx Outlet, ppmvd @ 15% O_2	≤ 9	≤ 4.5	≤ 3.0	≤ 2.0
NH_3 Slip, ppmvd @ 15% O_2	≤ 10	≤ 10	≤ 10	≤ 10
Δp Across Catalyst, in wg	≤ 1.8	≤ 2.0	≤ 1.8	≤ 2.5
Design Life	The earlier of 36 months from first gas-in or 39 months from contracted delivery			

*Guarantee performance is based on the attached Cormetech, Inc. Catalyst Technical Terms and Conditions and the following:

1. Maldistribution criteria:
   Flow ± 15% RMS; Temperature ± 20°F; NH_3:NOx Molar Ratio ± 5% RMS.

Design Flue Gas Conditions:

	Case 1	Case 2	Case 3	Case 4
Fuel	Gas	Gas	Gas	Gas
Flue Gas Flow Rate, lb/hr	3,474,000	3,474,000	3,474,000	3,474,000
Design Temperature, °F	650	650	650	650
Flue Gas Composition				
N_2, vol %	73.7	73.7	73.7	73.7
O_2, vol %	9.43	9.43	9.43	9.43
CO_2, vol %	5.2	5.2	5.2	5.2
H_2O, vol %	10.75	10.75	10.75	10.75
Ar, vol %	0.92	0.92	0.92	0.92
O_2, vol % dry	10.57	10.57	10.57	10.57
Inlet NOx, ppmvd @ 15% O_2	27.7	9.6	9.6	9.6
NOx lb/hr	243	84.7	84.7	84.7

General Terms and Conditions:
Cormetech, Inc. General Terms and Conditions of Sale, attached.

CORMETECH, INC.

Catalyst Technical Terms and Conditions

Warranty Conditions

1. Unit operating conditions shall be within the limits of design cases specified in SCR Catalyst Quotation.

2. The catalysts must be handled, operated, and maintained according to Cormetech instruction.

3. Cormetech maintains warranty protection as long as normal furnace start-up and shut-down procedures are followed and no moisture other than from flue gas or ambient air is present. The allowed start-up and shut-down temperature gradient for the catalyst is 10°C/min below and 60°C/min above the flue gas dew point.

4. Catalyst has been designed to accommodate profile maldistributions, based on a Normal Distribution, per SCR Catalyst Quotation.

5. Cormetech is not responsible for catalyst deterioration caused by aqueous ammonia drainage or water contact to the catalyst.

6. Suitable means must be employed, if needed, to clean catalyst masked or plugged by firing of particulate producing fuel. Customer will inspect visually at shutdowns and clean, as needed.

7. Access must be provided to Cormetech for visual inspection and catalyst sampling. Cormetech reserves the right to review the Unit's operating data at any time during the warranty period.

8. Customer must provide catalyst samples to Cormetech no less than annually during the warranty period, in order to maintain warranties.

9. Customer will provide a copy of all procedures and methods of analysis to be employed in catalyst evaluation for Acceptance and anytime throughout the warranty period.

Warranty Fulfillment

1. Cormetech's warranties are fulfilled at the end of the period stated in SCR Catalyst Quotation if the results of on-site tests indicates that the performance values, shown in SCR Catalyst Quotation, are met.

2. If the results of on-site tests during the warranty period indicates that the warranted values are not being met, Customer will conduct an on-site investigation to determine the cause of non-performance. If the catalyst is suspect, Cormetech will conduct laboratory tests, according to the conditions specified in SCR Catalyst Quotation, to verify the catalyst performance.

3. If the results of the laboratory tests indicate that the warranted values are being met, Cormetech's warranties will be deemed in fulfillment at this time and Customer will continue their investigation to determine the cause of non-fulfillment. Customer will compensate Cormetech for the cost of laboratory evaluation.

4. If the results of the laboratory tests indicate that the warranty values are not being met, Cormetech will, at its option, repair, replace, or add catalyst at its cost to meet the required performance values. Cormetech will absorb cost of laboratory evaluation.

CORMETECH, INC.
General Terms and Conditions of Sale

1. DEFINITIONS:
"Buyer" means the firm or company which places the order and purchases the Goods from Seller.
"Seller" means Cormetech, Inc.
"Goods" means the SCR Catalyst to be purchased by the Buyer.
"Order" means the purchasing order placed by the Buyer for the supply of the Goods.
"Specifications" means Seller's written technical description of the Goods purchased pursuant to the Order therefor and Seller's acceptance thereof.
"Owner" means the person, firm or company to whom the Buyer furnishes the plant including the Goods supplied by the Seller.

2. CONTRACT:
The contract for the purchase and sale of Goods shall be deemed to have been entered into by and between the Buyer and the Seller when, upon receipt of the Buyer's Order for such Goods, the Seller sends an acceptance in writing, within the time limit for such acceptance specified in such Order, executed by the duly authorized representative of Seller. Neither the Buyer nor the Seller shall be bound by any variation, waiver of, or addition to these general terms and conditions unless otherwise agreed by both parties in a writing executed by their duly authorized representatives. Except as otherwise provided in an express written agreement, these general terms and conditions shall govern in the event of any conflict with any terms or conditions proposed by the Seller or Buyer whether or not contained in any order or acceptance, or applicable in previous transactions, practice or course of dealings.

3. LIAISON PERSONNEL:
The Seller, immediately upon receiving Buyer's Order for Goods, may appoint an appropriate person for the performance of Seller's obligation to Buyer with respect to the Goods, to whom all communication thereon shall be directed.

4. DELIVERY:
The method of packing of the Goods shall be in accordance with the agreement of the Buyer and Seller and if no agreement has been reached, the Seller shall take all reasonable steps to prevent damage to or deterioration of the Goods in transit to their destination as specified in the accepted order.
The purchase price for Goods sold pursuant to an accepted purchase order shall include the cost of packing as mentioned above.

5. WARRANTY, QUALITY AND DESCRIPTION:
Seller hereby warrants to Buyer that at the time of delivery, the Goods sold to Buyer will conform to the written specifications set forth in Catalyst Technical Terms and Conditions to acceptable quality levels normally supplied by Seller in connection with the sales of said Goods. Seller will, solely at its option, repair or replace Goods which fail to meet the Terms and Conditions of this limited warranty.
In addition, Seller warrants that the performance of the Goods will, under the conditions specified in Catalyst Technical Terms and Conditions for the period set forth therein meet the performance criteria under the conditions specified therein. Verification of such performance guarantee will be accomplished as specified in Catalyst Technical Terms and Conditions, through the use of laboratory tests.
In the absence of specific alternate language, warranty period is on a calendar basis and begins at first gas-in and no later than three (3) months after scheduled delivery. Specific warranty period and terms are as set forth in the Catalyst Technical Terms and Conditions.
In the event Goods are stored and handled between the time of delivery and installation, Buyer shall provide adequate and appropriate facilities for storage of the Goods. Goods shall be handled according to Seller's Catalyst Handling Manual.
THE FOREGOING WARRANTY AND THE WARRANTY SET FORTH IN SECTION (15) ARE IN LIEU OF ALL OF THE WARRANTIES EXPRESSED OR IMPLIED, INCLUDING, BUT NOT LIMITED TO, IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

6. SPECIFICATIONS:
The Goods sold hereunder shall comply with the written specifications set forth in Catalyst Technical Terms and Conditions. The performance of such Goods will vary in accordance with individual specifications, operation, and maintenance of the systems in which they are installed. Buyer has the sole responsibility for the completeness and accuracy of information. Seller will rely exclusively on such information to make recommendations on the type and volume of Goods to be used in Owner's facility.

7. MODIFICATION IN SPECIFICATIONS:
The specifications may be modified and/or changed at any time provided that both the parties agree in writing. Such agreement may include reasonable adjustments of the price, time of delivery of the Goods and other terms before such modifications and/or changes are carried out.

8. DRAWINGS:
Drawings, such as, drawings for approval, drawings for installation, drawings showing the finished conditions of the Goods, instruction manuals, etc., shall be supplied by the Seller to the Buyer strictly in accordance with and by the time instructed in the Specification or in the accepted order.

9. INSPECTION AND TEST AT SELLER'S WORKS
Upon reasonable notice and at reasonable times, the Buyer shall have access to the office of the Seller or, subject to written consent of such supplier, the office and manufacturing operations of Seller's supplier for expedition of manufacturing or inspection of the Goods in the course of a normal working day during the period from the date of the Order to the date of shipment of the Goods. If such inspection shall be done at the factory of Seller's supplier, the Seller shall also inform the Buyer of the details of such visit in advance. Buyer shall inspect all Goods within thirty (30) days of delivery of such Goods and immediately report to Seller in writing any claims for breach of warranty set forth in Section (5) above. All Goods which remain uninspected after such thirty (30) days shall be deemed accepted by Buyer.
In the event that the Goods are rightfully rejected at the time of inspection for failure to conform to the provisions of Section (5) above, the Seller shall, solely at the Seller's option, repair or replace such Goods.

10. PRODUCTION SCHEDULE:
When requested, the Seller will provide the Buyer with the production schedule setting forth the estimated dates for the issuance schedule of drawings, order of material, fabrication schedule, inspection schedule, if any, for the Goods purchased pursuant to the acceptance order, and during the contractual period, keep the Buyer informed monthly of actual progress in providing the Goods.
In case there is some unexpected factor or occurrence which prevents normal progress of production or manufacturing, the Seller shall inform the Buyer promptly.

11. SHIPPING INSTRUCTION:
The Goods subject to Buyer's Order shall be sold FOB Jobsite, unless otherwise indicated, and the Buyer or Seller on Buyer's behalf pursuant to Buyer's instructions will book and arrange appropriate transportation from such site. The Seller shall provide the following information regarding such Goods.

a. Net weight, gross weight, freight tons
b. Measurement of each packing or parcel
c. Number of packages
d. Name of loading port
e. Date of cargo readiness

12. LIMITATION OF LIABILITY:
If, owing to force majeure as defined in Section (14) hereof, the Seller is unable to deliver the Goods within ninety (90) days of the delivery time specified in the accepted order for such Goods, then provided that the Seller shall have given Buyer written notice of such force majeure, the Buyer shall grant the Seller extension of time, as may be reasonable, to complete performance.
The liability of the Seller, its supplier, their agents, employees, subcontractors and sub-suppliers with respect to any and all claims arising out of the performance or non-performance of obligations in connection with the design, manufacture, sale, delivery, storage, erection or use of the Goods or the rendition of other services in connection therewith, whether based on contract, warranty, tort (including negligence), strict liability or otherwise, shall not exceed in the aggregate the purchase price for the Goods and shall in no event include: damages for loss of profits or revenue or the loss of use of either; loss by reason of plant shutdown or inability to operate at rated capacity; increased expense of operation of plant or equipment; increased costs of purchasing or providing Goods, equipment, materials, supplies or services; costs of replacement power or capital; claims of Owner's customers; inventory or use charges; or any other incidental or consequential damages of any nature.
This limitation of liability shall prevail over any conflicting or inconsistent provisions contained in any of the documents comprising the contract for the Goods, except to the extent such conflicting or inconsistent provisions further restrict the Seller's liability.

13. PRICE AND PAYMENT:
All payments shall be made within thirty (30) days after the presentation of the invoice therefor, unless otherwise indicated.
Seller will meet delivery schedule required by contract. In the event Buyer delays requested delivery, terms of payment shall commence per original schedule. Seller shall notify Buyer of all resultant fees and requirements due to delay, including but not limited to, handling, storage, and truck cancellation fees. Buyer shall be invoiced for said fees upon shipment.
Payments received after date specified on invoice will be assessed a monthly finance charge (12% per annum).

14. FORCE MAJEURE:
Force majeure shall mean unavoidable causes beyond the control of the Seller, including but not limited to, acts of God, war (declared or undeclared), acts of governmental authorities, riot, revolution, civil commotion, fires, strikes (and other labor disputes, sabotage), or epidemic, and other similar matters beyond the reasonable control of a party.
Should the causes of force majeure prevent the total or partial performance required concerning the purchase of Goods, the party claiming force majeure shall promptly advise the other party at the beginning and end of such force majeure and furnish the other party a written notice identifying the nature of the circumstances of force majeure promptly.
In cases of force majeure described above, there shall be consultation between the parties to discuss the effect on the contractual obligations of both parties. For delays and/or non-performance of the obligations due to force majeure, the affected party shall be entitled to an extension of time equal to that of the delay plus such additional time as is reasonably necessary to resume performance of its obligations.

15. PATENTS:
The Seller warrants freedom from patent infringement on those Goods sold under an accepted order when such Goods are used for the purposes normally intended.
Purchase of this product from Cormetech, Inc. includes a license to use this product in the practice of the method claimed in U.S. Patent 4,358,428.

16. ASSIGNMENT:
Neither the contract nor any part of it shall be assigned or transferred to any third party without the other parties' prior written consent where such consent shall not be unreasonably withheld.

17. TAXES:
Any applicable sales, use, excise or other tax shall not be included in Seller's quoted price for Goods.

18. BACKCHARGE:
Seller is not liable, whether by backcharge or otherwise, for the cost of work performed or material or equipment furnished by the Buyer or any third parties unless such work and the costs thereof have been approved in writing by an authorized representative of Seller.

19. NON-DISCLOSURE:
Data, drawings, specifications, or other technical information furnished directly or indirectly, in writing or otherwise, to Seller by Purchaser or to Purchaser from Seller pursuant to this order shall in no event become the property of the receiving party and shall be used only in fulfilling the obligations imposed by this order and shall not be duplicated or disclosed to others or used in whole or in part for any other purpose. Such furnishing of data, drawings, specification, or other technical information shall not be construed as granting any rights whatsoever, express or implied, under patents or privileges of the disclosing party.

20. TERMINATION:
Upon notice, Seller will take all reasonable measures to cease production in-process and to minimize the cost of goods and services procured for fulfillment against this contract. It is recognized that the Goods and Services contracted herein are of custom design and manufacture, the value of which is not reasonably expected to be recoverable by the Seller in the event of termination.
Therefore, upon termination, Seller will submit to Buyer an accounting of all Goods and Services directly allocated to fulfillment of this contract including but not limited to finished Goods, Goods-in-process, non-cancelable subcontracts, and custom dies. Forced disruption of manufacturing in process may result in additional expense which is the sole responsibility of Buyer. It is expected that raw materials may be purchased and production proceed against the requirements of any or all of the defined scope of contract at any time following contract award by Buyer. Seller will keep Buyer informed of progress against contract.

Reference 1

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

FAX NUMBER: 913-458-2934 913-458-2936 913-458-2939

FACSIMILE TRANSMISSION

TO: Mr. Fred Booth
COMPANY: Engelhard
FAX NUMBER: (410) 569-1841
TELEPHONE NUMBER: (410) 569-0297
FROM: Don Wolf
EXTENSION: 2845 LOCATION: P4G1

B&V PROJECT: 063045
B&V PHASE: 0042
B&V FILE:
PAGE: 1 of 2
DATE: June 14, 1999

NOTE TO RECEIVING OPERATOR
In the event of incomplete transmission, please call (913) 458-7218.

TRANSMITTAL DATE/TIME: ______ OPERATOR'S INITIALS: ______

SUBJECT: High Temperature SCR Catalyst for Simple Cycle Combustion Turbines

MESSAGE: As we discussed on the phone this morning Black & Veatch is assessing the experience, feasibility, potential NO_x reductions, and costs for high temperature SCR catalyst located at the outlet of 3 different simple cycle combustion turbines (SCCT).

Please provide the following information:

1. An experience list of Engelhard SCR catalyst applications on SCCT including the inlet and outlet NO_x emissions.
2. A review of the information provided below for the 3 SCCT machines to determine the maximum practical NO_x reduction that can be achieved with high temperature catalyst.
3. Provide cost or catalyst volume (if possible with the limited data and response time).

The 3 SCCTs being evaluated have the general design criteria listed in the table below. Please note that no specific data is available at this time since this is a very cursory review. Therefore, please assume the data below is full load data only.

	GE 7241 (7FA)	GE 7121 (7EA)	GE LM6000 PC Sprint
Exhaust Flow, lb/hr	3,427,200	2,314,800	1,008,000
Exhaust Temperature, F	1,116	998	842
NO_x, ppmvd @ 15% O_2	9	9	22

Please provide the requested information by noon (CST) Tuesday June 15, 1999. If you have any questions please do not hesitate to call me at (913) 458-2845. I appreciate your attention to this matter. Thank you.

P451
2845

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	June 15, 1999	NO. PAGES	4	(INCLUDING COVER)
TO:	BLACK & VEATCH ATTN: Don Wolf ENGELHARD ATTN: Nancy Ellison	FAX 913-458-2934		
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841		

RE: **Simple Cycle Turbines**
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB99465

We provide Engelhard Budgetary Proposal EPB99465 for Engelhard **NOxCAT ZNX™** High Temperature SCR Catalyst system components per your FAXed request of June 14, 1999.

Our Budgetary Proposal is based on:

- Gas Turbine operating in simple cycle mode;
- SCR Catalysts for NOx reductions from noted inlet levels to 2.5 ppmvd @ 15% O_2 with ammonia slip of 5 ppmvd @ 15% O_2;
- Nominal 5.0" Delta P across SCR;
- Scope as noted. Please note that we have assumed horizontal gas flow through the SCR reactor and the use of 28% aqueous ammonia.
- Please note that turbine exhaust flow for the GE7FA is cooled with an ambient air injection system to reduce the gas temperature at the SCR to 1,025F. The cost of the components for this turbine is included. The ductwork to hold the catalysts and the transitions and any flow straighteners are not included in scope detailed herein.
- We have indicated cross section area required to meet the conversions and pressure drop. Inside liner width and height can be varied while maintaining same cross sectional area.
- Three (3) Year Performance Guarantee (expected life five to seven years).

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

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

cc: Nancy Ellison - Proposal Administrator

ENGELHARD

Black & Veatch 063045
Simple Cycle Turbines
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99465
June 15, 1999

ENGELHARD CORPORATION
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEMS

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **NOxCAT ZNX™** ceramic substrate SCR system components summarized herein.

NOxCAT ZNX™ High Temperature SCR Catalyst System: Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **NOxCAT ZNX™** SCR catalyst in modules;
- Internal support structures for catalyst modules (frame);
- Ambient Air injection cooling system components (GE 7FA);
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: 28% Aqueous Ammonia
  - Pre-piped & wired (including all valves and fittings) Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
    - Blowers (on/off/flow indicators)
    - Air/ammonia flow indicator and controller
    - System pressure indicators
    - Main power disconnect switch

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

BUDGET PRICES: **See Performance Data**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	9,000 hours of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

**Operation is considered to start when exhaust gas is first passed through the catalyst.*

DOCUMENT / MATERIAL DELIVERY SCHEDULE

Drawings / Documentation -	10 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Operating manuals	
Material Delivery	20 - 24 weeks after approval and release for fabrication

SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbines
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	To 2.5 ppmvd @ 15% O_2
NH3 Slip:	5 ppmvd@15%O_2
Pressure Drop through SCR	Nom. 5"WG

ENGELHARD

Black & Veatch 063045
Simple Cycle Turbines
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99465
June 15, 1999

P

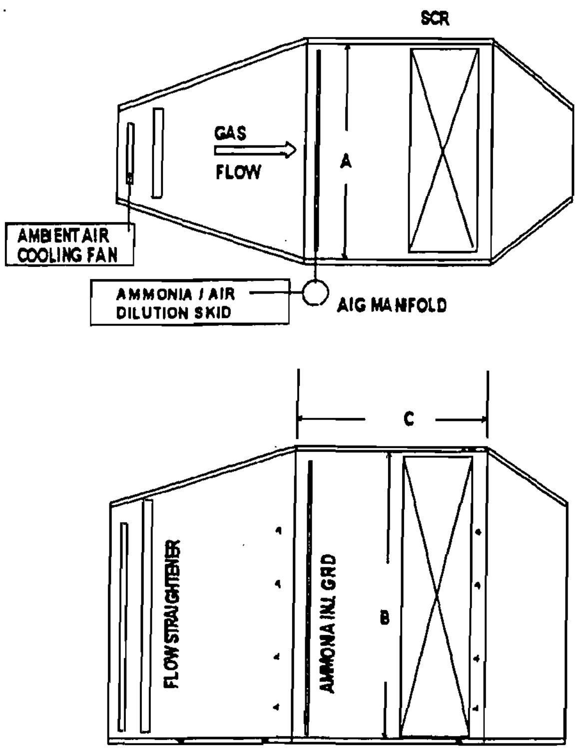
Performance Data

TURBINE		GE 7FA	GE 7EA	GE LM6000
ASSUMED AMBIENT		95	95	95
GIVEN TURBINE EXHAUST TEMPERATURE, F		1,116	998	842
GIVEN TURBINE EXHAUST FLOW, lb/hr		3,427,200	2,314,800	1,008,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL.	N2	74.06	73.24	73.24
	O2	12.50	13.42	13.42
	CO2	3.90	3.80	3.80
	H2O	8.65	8.65	8.65
	Ar	0.89	0.89	0.89
AMBIENT COOLING AIR FLOW, lb/hr		368,745	0	0
TOTAL FLOW – TURBINE EXHAUST + AMBIENT - lb/hr		3,795,945	2,314,800	1,008,000
AMBIENT + EXHAUST GAS ANALYSIS, % VOL.	N2	74.75	73.24	73.24
	O2	13.10	13.42	13.42
	CO2	3.53	3.80	3.80
	H2O	7.82	8.65	8.65
	Ar	0.80	0.89	0.89
CALCULATED AIR + GAS MOL. WT.		28.42	28.40	28.40
GIVEN: TURBINE NOx, ppmvd @ 15% O_2		9.0	9.0	22.0
CALC.: TURBINE NOx, lb/hr		55.9	32.4	34.5
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE		8.7	9.0	22.0
GAS TEMP. @ SCR CATALYST, F		1,025	998	842
DESIGN REQ. SCR CATALYST NOx OUT, ppmvd @ 15% O2		2.5	2.5	2.5
NH3 SLIP, ppmvd @ 15% O2		5	5	5
SCR PRESSURE DROP, 5"WG – Nom..				
GUARANTEED PERFORMANCE DATA				
SCR CATALYST NOx CONVERSION, % - Min.		72.2%	72.2%	88.6%
NOx OUT, lb/hr - Max.		15.5	9.0	3.9
NOx OUT, ppmvd @ 15% O2 - Max.		2.4	2.5	2.5
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr		96	55	51
NH3 SLIP, ppmvd @ 15% O2 - Max.		5	5	5
SCR PRESSURE DROP, "WG - Max.		4.5	4.0	4.5
REACTOR INSIDE LINER AREA - A x B, sq ft		**2100**	**1350**	**640**
SCR SYSTEM		**$4,015,000**	**$2,711,000**	**$1,558,000**
REPLACEMENT SCR CATALYST MODULES		**$2,496,000**	**$2,057,000**	**$1,111,000**

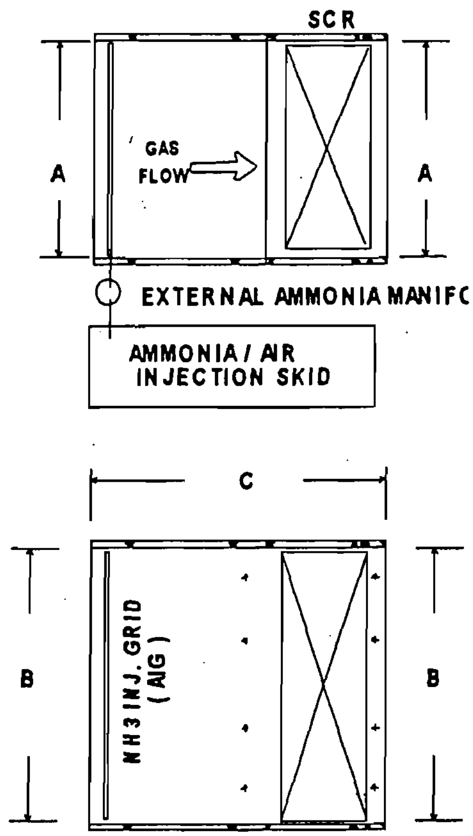
ENGELHARD

Black & Veatch 063045
Simple Cycle Turbines
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99465
June 15, 1999

Dimensions / Sketch: GE 7FA
Required Cross Sectional Area
Inside Liner Width x Inside Liner Height
(A x B) sq. ft.
Reactor Depth (C) 12'-0"



Dimensions / Sketch:
Required Cross Sectional Area
Inside Liner Width x Inside Liner Height
(A x B) sq. ft.
Reactor Depth (C) 12'-0"



ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	June 15, 1999	NO. PAGES	2	(INCLUDING COVER)
TO:	BLACK & VEATCH ATTN: Don Wolf 24G1/2845		FAX 913-458-2934	
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841		

High Temp SCR Experience attached.

Engelhard SCR System Experience List

Application	Catalyst	Flow (lb/sec)	Fuel	Start-Up
(1) BBC (50 MW)	VNX	650	NG	11/90
(1) Kawasaki 1 MW	ZNX	23	NG	2/91
(1) Allison 3.5 MW	VNX	38	NG	9/91
(1) Rolls Royce 25 MW	VNX	259	NG	8/92
(2) Westinghouse 251	VNX	422	NG	10/92
(1) GE Frame 7	VNX	669	NG	1Q/93
(1) LM-2500	VNX	157	NG	5/93
(2) LM-6000	VNX	283	NG	4Q/93
(1) LM 5000	VNX	248	NG	1993
(1) LM 5000	VNX	342	NG	1994
(1) GE Frame 6	ZNX	305	NG	1/95
(1) Solar T4500	ZNX	41	NG	1/95
(2) GE Frame 5	ZNX	212	NG	1/95
(1) GE Frame 7	VNX	638	NG	2Q/95
(1) GE Frame 6	VNX	330	NG	1996
(3) ABB GT11N	ZNX	728	#2 Oil	6/96
(1) 2000 Hp	VNX	97	NG	1985
(2) 4000 Hp	VNX	23	NG/DF	1986
(3) 1500 Hp	ZNX	9	DF	5/91
(1) 800 Hp	VNX	8	NG	1993
(1) Refinery Heater	VNX	84	NG	10/90
(1) Refinery Heater	VNX/ZNX	46	NG	10/90
(1) Boiler 1 MW	VNX	26	NG	10/90
(1) Annealing Furnace	VNX	29	NG	1991
(5) Refinery Heater	VNX	16-31	NG	3/91
(1) Refinery Heater	VNX	39	NG	6/91
(1) Refinery Heater	VNX	120.6	#6/NG	1/94
(1) Refinery Heater	VNX	137.8	#6/NG	5/94
(1) Refinery Heater	VNX	110.6	#6/NG	5/94
(1) Utility Boiler (250 MW)	PNX	404	Coal	9/96
(1) Process Off-Gas	ZNX	4	CP	8/90
(1) Nitric Acid Plant	VNX	99	NG	3/91
(1) Process Off-Gas	ZNX	4	CP	1/94
(1) Utility Boiler - LD	VNX		Coal	1985
(8) Gas Turbines	VNX/ZNX		NG	1987
(2) Utility Boiler - LD	VNX/ZNX		Coal	1987
(1) Utility Boiler - HDW	VNX/ZNX		Coal	1989
(1) Utility Boiler - HDD	VNX/ZNX		Coal	1989
(1) Utility Boiler - LD	VNX		Coal	1991
(1) Utility Boiler - HD	VNX		#6 Oil	1991
(2) Turbines	VNX/ZNX		#2 Oil	1994
(1) Utility Air Preheater	PNX		NG/#2 Oil	1994/95
(1) Utility Boiler - HDW	PNX		Coal/NG	2Q/95
(1) Utility Boiler - HDD	PNX		Coal	3Q/95
(1) Utility Boiler - HDD	PNX		Coal	4Q/95

ATTACHMENT E

Table 1

NO_x Control Alternative Capital Cost (Revised)

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts and Ammonia Injection	1,106,000	NA	Scaled from previous projects.
Ductwork and Catalyst Reactor	710,000	NA	Based on conceptual ductwork arrangement
Control/Instrumentation	100,000	NA	Estimated; includes controls and monitoring equipment.
Ammonia Storage	167,000	NA	Scaled from previous projects
Balance of Plant	833,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering, 6 % Retrofit Factor.
Total Direct Capital Cost	2,916,000	Base	
Indirect Capital Costs			
Contingency	729,000	NA	25% of Direct Capital Cost
Engineering and Supervision	208,000	NA	10% of Purchased Equipment Cost
Construction & Field Expense	104,000	NA	5% of Purchased Equipment Cost
Construction Fee	208,000	NA	10% of Purchased Equipment Cost
Start-up Assistance	42,000	NA	2% of Purchased Equipment Cost
Performance Test	35,000	NA	Estimated Cost
Total Indirect Capital Costs	1,326,000	Base	
Total Installed Cost	**4,242,000**	Base	

Table 2

NO_x Control Alternative Annual Cost (Revised)

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			
Catalyst Replacement	121,000	NA	Catalyst life of 3 yr. of equivalent operating hours (5.3 equivalent years)
Operation and Maintenance	16,000	NA	
Reagent Feed	18,000	NA	Assumes 1.4 stoichiometric ratio
Power Consumption	5,000	NA	
Lost Power Generation	150,000	NA	Back pressure on combustion turbine
Annual Distribution Check	15,000	NA	Required for SCR
Total Direct Annual Cost	325,000	NA	
Indirect Annual Costs			
Overhead	7,000	NA	60% of O&M Labor
Administrative Charges	85,000	NA	2% of Total Installed Cost
Property Taxes	42,000	NA	1% of Total Installed Cost
Insurance	42,000	NA	1% of Total Installed Cost
Capital Recovery	355,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	531,000	NA	
Total Annual Cost	**856,000**	NA	
Annual Emissions, tpy	18	90	Emissions from BACT for 5,000 hrs of natural gas firing
Emissions Reduction, tpy	72	NA	Emissions calculated from BACT
Total Cost Effectiveness, $/ton	**11,889**	NA	Total Annual Cost/Emissions Reduction

ATTACHMENT F

Table 3
NO_x Control Alternative Cost
With and Without Contingency

	SCR W/ Contingency	SCR W/out Contingency
Direct Capital Cost		
Catalysts and Ammonia Injection	1,106,000	1,106,000
Ductwork and Catalyst Reactor	710,000	710,000
Control/Instrumentation	100,000	100,000
Ammonia Storage	167,000	167,000
Balance of Plant	833,000	833,000
Total Direct Capital Cost	2,916,000	2,916,000
Indirect Capital Costs		
Contingency	729,000	0
Engineering and Supervision	208,000	208,000
Construction & Field Expense	104,000	104,000
Construction Fee	208,000	208,000
Start-up Assistance	42,000	42,000
Performance Test	35,000	35,000
Total Indirect Capital Costs	1,326,000	597,000
Total Capital Cost	4,242,000	3,513,000
Direct Annual Cost		
Total Direct Annual Cost	325,000	325,000
Indirect Annual Costs		
Overhead	7,000	7,000
Administrative Charges	85,000	70,000
Property Taxes	42,000	35,000
Insurance	42,000	35,000
Capital Recovery	355,000	294,000
Total Indirect Annual Costs	531,000	441,000
Total Annual Cost	**856,000**	**766,000**
Annual Emissions, tpy	18	18
Emissions Reduction, tpy	72	72
Total Cost Effectiveness, $/ton	**11,889**	**10,639**

ATTACHMENT G

BLACK & VEATCH

TELEPHONE MEMORANDUM

B&V Project 63812.0030
7/21/99
11:30 am

Puerto Rico-Simple Cycle Firing No. 2 Fuel Oil
NOx Emission Problems

From: Mr. Harish Patel
Company: EPA, Region 2, New York
Phone No.: (212) 637-4046

Recorded by: Greg Holscher

The following is a telephone conversation regarding the Cambalache Plant in Puerto Rico. The plant has a simple cycle combustor capable of firing No. 2 fuel oil. The main concern was whether the facility was meeting their permit requirements for NOx output.

Mr. Patel informed me of the following:

1) The Puerto Rico plant was permitted for NOx at 10 ppm and ammonia slip at 10 ppm.
2) They are using water injection followed by an SCR.
3) They are having problems meeting their permit with the SCR.
4) Using a simple cycle turbine, which has a high temperature outlet. They are trying to use a zeolite catalyst for the SCR. The zeolite catalyst does not seem to be working in the SCR like it did in the laboratory.
5) To keep the NOx level low, they are increasing the amount of ammonia injected into the system (decrease NOx results in increasing ammonia slip).
6) The ammonia delivery system is finite, meaning they can only inject so much ammonia into their system.
7) After a few weeks/months the NOx level is slightly increasing. The level of NOx is about 20 to 25 ppm.
8) The ammonia slip is also increasing to about 30 to 40 ppm.
9) When the water injection-SCR system first went into operation, the NOx levels were at about 10 ppm, but are estimated to steadily increase to 42 ppm (42 ppm is the limit using only water injection).
10) Another contact is in Puerto Rico: Mr. Francisco Claudio at (787) 729-6951 Ext. 258

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

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BUREAU OF AIR REGULATION

Kissimmee Utility Authority
Cane Island – Unit 1 PSD Permit Amendment Request

B&V Project 24489.018
B&V File 14.1000
October 28, 1999

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Response to Request for Additional Information

0970043-007-AC
PSD-FL-182(a)

Attention: Al Linero
Administrator, New Source Review Section

Gentlemen:

On behalf of Kissimmee Utility Authority (KUA, the Applicant), Black & Veatch (B&V) is herewith submitting the additional information requested in Florida Department of Environmental Protection's (FDEP) September 24, 1999 response to the Applicant's Unit 1 permit amendment application of August 31, 1999. As FDEP is aware, General Electric (GE) has not been able to develop the technology for a dual fuel LM6000PA unit to meet a 15 ppmvd natural gas NOx emission rate, and cannot guarantee when, if ever, such technology may be available. Thus, KUA is requesting an amendment to Construction Permit No. AC49-205703 (PSD-FL-182) and the Initial Title V Air Operating Permit, Permit No. 0970043-002-AV, to modify Unit 1's NOx emission limit during natural gas firing from 15 to 25 ppmvd, based on the revised BACT analysis and an operating limit of 5,000 hours per year. As a result of the requested permit amendment, annual potential emissions from Unit 1 will be less than those currently allowed. FDEP's specific information requests, along with the Applicant's responses, are provided below.

Request Item 1:

What are the lowest levels of NO_X that can possibly be consistently achieved with water injection with the LM6000PA engine, based on the experience of KUA and the engine manufacturer? Are lower emissions achievable with higher water injection rates?

Response:

Historical Unit 1 emission test data and relative accuracy test audit (RATA) data (Attachment A) from 1995 through 1998 indicate that natural gas fired NOx emission levels have ranged from approximately 20 ppmvd @ 15% O_2 to just under 25 ppmvd @ 15% O_2 with water injection. The lowest levels consistently achieved are best represented by recent continuous emissions monitoring (CEM) data from October 12, 1999. These data, included as Attachment B, reveal an average NOx emission level for Unit 1 of 21.4 ppmvd @ 15% O_2 for a 3-hour period on October 12, 1999. The average water-to-fuel injection ratio during this period was 1.03:1. It should be noted that compliance with Unit 1's NOx emission limit is determined with a CEM system based on a 1-hour averaging period (i.e., any 60 minute period). Based on the October 12, 1999 CEMs data, Unit 1 consistently achieves a NOx emission level of approximately 22 ppm @ 15% O_2 based on a 1-hour averaging period.

The water injection control systems for Unit 1 were configured by GE to achieve the delicate balance of minimizing NOx emissions while optimizing turbine performance and limiting CO formation. GE's recommended water-to-fuel ratio for LM6000PC combustion turbines firing natural gas is typically 1.18:1 to achieve NOx levels of 25 ppm, while KUA's experience firing natural gas in the LM6000PA combustion turbine demonstrates that approximately a 1:1 water-to-fuel ratio is necessary to achieve NOx emission levels less than 25 ppm. While higher water-to-fuel ratios may result in limited additional NOx reduction (certainly not down to the 15 ppm level), such ratios are not recommended by GE, and may result in reduced combustor life and increased combustor inspections, increased equipment erosion and maintenance costs, unstable combustor flames and potential flame extinction, and high combustor dynamic pressures. GE does not recommend any higher water injection rates than are necessary to achieve NOx emission levels of 25 ppm. Please refer to GE's letter of October 19, 1999 to KUA regarding this issue (included as Attachment C).

Request Item 2:

Please evaluate the applicability of spray intercooling to reducing NO_X emissions from this engine.

Response:

GE currently offers LM6000PC combustion turbines with spray intercooling technology, also known as SPRINT. There have been several inquiries to GE relative to use of SPRINT technology on LM6000PA combustion turbines, but these have been with an emphasis on providing hot day power augmentation (increasing turbine output on high end days), rather than as a method for enhanced NOx control. To date, SPRINT technology has not been used for emission reductions from a LM6000PA combustion turbine, nor has a decision been made whether GE will consider adapting SPRINT technology for modification of LM6000PA field machines. Please refer to GE's letter of October 19, 1999 included as Attachment C.

Request Item 3:

The analysis provided proposed reducing allowable hours of operation firing gas from the current 8760 hours per year to 5000 hours per year. The application information for potential NO_X emissions shows that KUA proposes no reduction in hours of operation for fuel oil firing, allowing for a total of 6000 hours of operation per year (5000 hours for gas firing plus 1000 hours for oil firing). Based on information provided in annual operation reports, Unit 1 has operated 1096 hours in 1996 and 774 hours in 1997, for an average of 935 hours (firing primarily gas). Comparing past actual operation with proposed future operation shows that NO_X emissions will increase by approximately 105 tons per year. Please address this issue.

Response:

It is the Applicant's position that a hot-side SCR for Unit 1 became cost ineffective in the best available control technology (BACT) analysis when the annual hours of natural gas firing were limited to 5,000 h/yr. Furthermore, it is also cost ineffective at 8,760 h/yr. Results of the revised BACT analysis submitted with the application were intended to substantiate the requested modification of Unit 1's natural gas NOx emission limit from 15 ppmvd @ 15% O_2 to 25 ppmvd @ 15% O_2 on January 1, 2000. A reduction in fuel oil firing hours is neither relevant to the natural gas NOx limit for Unit 1, as it plays no role in achieving lower gas fired NOx emission limits, nor practical for KUA, who's natural gas fuel contracts and partnership with Florida Municipal Power Agency (FMPA) depend on the level of dual-fuel capability currently allowed. Test data while firing distillate fuel oil (Included in Attachment A) clearly indicate Unit 1's ability to achieve compliance with the 42 ppmvd @ 15% O_2 NOx emission limit. For these reasons, KUA is not proposing a reduction in the distillate fuel oil firing capability of Unit 1.

A comparison of past actual emissions to future potential emissions is typically performed to determine whether or not a modification (physical change or change in the method of operation of an emission unit) results in a significant emission increase with respect to Prevention of Significant Deterioration (PSD) applicability. It must however be made very clear that KUA is neither proposing a physical modification nor change in the method of operation of Unit 1, but merely a relaxation of the 15 ppm NOx emission limit for natural gas firing scheduled to take effect January 1, 2000. The 15 ppm was based on the specific representations from GE, that GE had emerging technology designed to lower LM6000PA emissions to 15 ppm during natural gas firing. A more accurate and representative comparison of NOx emissions, with regard to the proposed request, is to compare the current permit "Potential Emissions" and future proposed permit "Potential Emissions". The following comparison of "Potentials" to "Potentials" illustrates a 49.7 tpy reduction in NOx emissions from Unit 1 based on an emission limit of 25 ppm and 5,000 h/yr of natural gas operation.

Permitted Emission Levels

(36 lb/h (25ppm) * 7,760 h/yr) + (63 lb/h (42 ppm) * 1,000 h/yr) = 171.2 tpy

Proposed Emission Levels

(36 lb/h (25ppm) * 5,000 h/yr) + (63 lb/h (42 ppm) * 1,000 h/yr) = 121.5 tpy

Additional Emissions Reduction

(171.8 tpy (Permitted Emission Level) – 121.5 tpy (Proposed Emission Level)) = 49.7 tpy

<u>Request Item 4:</u>

The application proposes no reduction in hours for oil firing even though annual operation reports show that the greatest amount of oil firing was in 1998 with approximately 13 full load hours on oil. It appears that KUA could propose a dramatic reduction in allowable hours for oil firing without compromising the ability to operate the unit. Please comment and provide historical data showing the actual hours of operation firing gas and oil as well as the fuel consumption by fuel type for calendar years 1998 through 1994. We wish to confirm the information available in our records from annual operation reports.

Response:

As previously stated in response to Item 3, KUA is currently meeting the permitted fuel oil emission limit of 42 ppm, and does not intend to propose a reduction in allowable hours of fuel oil firing. The fuel oil capability is required for backup capability due to the nature of natural gas and purchase power contracts for both KUA and FMPA. The following table summarizes Unit 1's actual operating hours and fuel consumption as requested.

Unit 1 – Historical Operating Hours and Fuel Consumption

Year	Fuel	Maximum Documented Operation (h/yr)	Fuel Consumption[a]
1995	Natural Gas	2,201	762.2 Mscf/yr
	Fuel Oil	2	4,835.4 gal/yr
1996	Natural Gas	404	139.9 Mscf/yr
	Fuel Oil	1	2,417.7 gal/yr
1997	Natural Gas	772	267.3 Mscf/yr
	Fuel Oil	2	4,835.4 gal/yr
1998	Natural Gas	1079	373.7 Mscf/yr
	Fuel Oil	17	41,100.9 gal/yr

[a]The fuel consumption calculations are based on a fuel oil of heat content of 138,064 Btu/gal (HHV) and average fuel oil heat input of 338.8 MBtu/h, and a natural gas heat content of 1,042.5 Btu/scf (HHV) and average heat input of 361.0 MBtu/h.

Request Item 5:

Overall, the control cost effectiveness seems high. The analysis does not appear to have been based upon a vendor's quote for a hot SCR system for this installation; an actual quote should be obtained for this analysis. Below are specific points which appear questionable. The contingency of 25% (particularly on top of a 6% retrofit factor) seems very high given that this is commercially available technology.

A. The contingency of 25% (particularly on top of a 6% retrofit factor) seems very high given that this is commercially available technology.

B. The indirect capital costs were generally calculated as a percentage of the total direct capital cost, although more typically the direct installation costs (in the analysis shown as "balance of plant") are not used to estimate the indirect capital costs.

C. The rate for administrative charges, taxes and insurance at 5.75% is higher than a more typical 4% rate.

D. The nominal interest rate used for the capital recovery factor was 10% (the "real interest rate" shown of 5.5% plus apparently an anticipated annual rate of inflation of 4.5%) although 7% is more typical.

E. The charge for lost power generation from backpressure seems excessive, as does the stated increase in back pressure of 6 inches of water.

F. Catalyst life seems low at 3 years, particularly for a unit that fires primarily gas. The Department is aware of at least one vendor that will guarantee a catalyst life of 3 years inclusive of 1000 hours of annual oil firing, yet no NO_x reductions due to oil firing were included in the analysis.

G. The analysis did not consider the control effectiveness for the allowable use of fuel oil, and did not consider any reduction in annual Title V fees associated with the overall decrease in NO_x emissions from both gas and oil firing.

H. There is no description of what constitutes the "annual distribution check", or justification for this cost.

I. The economic analysis was based on only 5000 hours of operation on gas, although with installation of SCR there would be no reason to limit operation to less than 8760 hours per year.

J. The "starting point" for determining the NO_x reductions appears to presume the continuance of water injection. In the event that an SCR is installed, water injection (for gas as well as oil firing) should be able to be eliminated (or at least reduced). A higher "starting point" should therefore be assumed.

Accounting for these comments would serve to improve the cost effectiveness of SCR. Please provide the basis for costs used in the analysis where they differ from the recommendations in the above comments.

Response:

A quote was not obtained directly for this project. However, B&V had a current quote for a similar project that had been obtained only a month before the cost analysis was being developed for Unit 1. This quote is included as Attachment D along with the calculation performed to adjust this quote to the conditions associated with Unit 1. As illustrated by the costs in the quote, high temperature SCR catalysts are extremely expensive in comparison to conventional SCR catalyst. Changes have been made to the revised BACT cost tables based on FDEP comments. These changes are shown in the enclosed Tables 1 and 2 of Attachment E. It should be noted, however, that these changes do not change the conclusions of the revised BACT analysis which show that installing a high temperature SCR on the Cane Island Unit 1 combustion turbine is not cost effective.

5a. The contingency of 25 percent is typical for studies of this level of detail and is the right level of contingency for this estimate. The contingency accounts for the fact that this is a preliminary design. The following items, which are not resolved at this stage in the project, can significantly impact the cost:

- An exact layout of the new SCR ductwork is not complete
- Location of ammonia storage is not established
- Catalyst prices are in state of fluctuation due to the NOx SIP call being proposed by the EPA for coal fired units
- Structural steel costs are currently volatile
- Labor costs are volatile

Table 3, included in Attachment F shows a comparison of the costs with and without the contingency included. It reasoned from Table 3, that removing the contingency does not result in the high temperature SCR being cost effective.

The six percent retrofit factor is required due to the additional costs associated with retrofit work. The following costs are included in the six percent value:

- Costs associated with lost power generation during the outage to tie in the new equipment.
- Costs associated with additional construction labor required to work around existing equipment at the plant.

5.b. Changes have been made to the costs in accordance with FDEP's comment. Revised costs are reflected in Tables 1 and 2 in Attachment E. Specifically, the Purchase Equipment Cost consists of catalyst and ammonia, ductwork and catalyst reactor, control/instrumentation, and ammonia storage.

5.c. Changes have been made to the costs in accordance with FDEP's comment. Revised costs are reflected in Tables 1 and 2 in Attachment E.

5.d. The capital recovery factor for this project was calculated incorrectly. It should have been based on an interest rate of 5.5 percent. Revisions to the costs using the correct capital recovery factor are shown in Tables 1 and 2 in Attachment E. Please note that this interest rate is less than the seven percent referenced in FDEP's Request for additional information.

5.e. The charge for lost power is based on taking the backpressure on the combustion turbine and converting it to lost kilowatts (kW's). This calculation is based on a graph provided to B&V by Westinghouse on another project. This is the standard calculation used by B&V for calculating lost generation. Once kW's are calculated, the kW's are multiplied by the hours of operation per year and the energy costs (in $/kWh) listed in Table 1 of the revised BACT included in the "Application". The back pressure of 6 inches w.g. was developed by taking the 4.5 in w.g. from the catalyst quote plus an additional 1.5 in w.g. due to the additional ductwork that will be required in Unit 1's retrofit. The extra 1.5 in w.g. would not be required for a new unit.

5.f. The catalyst in the quote has been guaranteed for 3 years worth of operating hours. Therefore, for Unit 1 (with only 5,000 hours of operation), the actual catalyst life is equivalent to 5.3 years. The catalyst costs listed in the revised BACT are for 5.3 years not 3 years. Manufacturers are guaranteeing a catalyst life of three years worth of operating hours. However, there are concerns about how well high temperature SCR's will last on a unit which has the potential to fire fuel oil. Included as Attachment G is a telephone memorandum discussing three oil fired units in Puerto Rico which have rapidly degrading, high temperature SCR catalysts. It should be noted that due to impurities in the oil, fuel oil firing degrades the catalyst even when ammonia is not being injected.

5.g. As previously discussed, no reduction in fuel oil fired emissions are required in this request for modification of the natural gas NOx emission limit and no evaluation of fuel oil NOx reduction is required or relevant to this process. Title V fee savings are not included in the BACT cost analysis, but neither are the training and development costs associated with the Title III - Risk Management Program which are required when ammonia is stored onsite. It is expected that the savings and incurred costs of these two items would nearly offset each other, and therefore were not included in the BACT cost analysis.

5.h. An annual distribution check is required to ensure the ammonia slip is minimized in the SCR system and to track catalyst life. The activities associated with this include NOx testing of the SCR catalyst inlet and outlet. Ammonia testing of the catalyst outlet is included and catalyst activity tests are also included. The costs are based on testing quotes from other projects.

5.i. A revised BACT analysis was performed based on the operating scenario of the Cane Island Power Park. If KUA proposed that Unit 1 would be operated 8,760 hours per year, then the revised BACT analysis would have been performed for 8,760 hours per year. However, we are proposing an operating limitation of 5,000 hours per year. Therefore, this is the operating scenario that should be used to perform the BACT analysis and is the information contained in the revised BACT submitted to FDEP as Attachment D of the "Request Letter".

5.j. As stated in the revised BACT, the analysis follows a "Top Down" approach as USEPA guidance authorizes, and the most stringent NOx control should be compared to the next most stringent NOx control technology analysis. Therefore, an SCR is compared to the next most stringent NOx control (water injection). If the revised BACT had compared SCR to conventional combustors without water injection, it would have skipped an important step in the NOx control alternatives. In addition, the revised BACT analysis would not have followed regulatory guidelines, which require a "Top Down analysis in which the most stringent technology is compared to the next most stringent technology. It seems inconsistent to suggest comparing SCR to conventional combustors when FDEP has a documented history of promoting in-combustion controls over post-combustion controls.

<u>Request Item 6:</u>

Please indicate whether any other (additional) means are available to obtain real offsetting reductions in NO_x emissions from the facility as a whole.

<u>Response:</u>

Short of installing SCR systems, which are clearly contrary to FDEP's documented history of promoting in-combustion controls over post combustion controls, limited annual operation of Unit 1 is the only practical option available to obtain real offsetting NOx reductions. In a meeting held in FDEP's offices on October 20, 1999, with parties from FDEP, KUA, and B&V attending, FDEP suggested a NOx emission cap for Units 1 and 2 as a method for obtaining real offsetting reductions in NOx emissions from the facility as a whole.

Specifically, Mike Halpin suggested an annual ton per year NOx emission cap for Units 1 & 2 based on the following formula:

- Unit 2's annual NOx ton per year permitted potential to emit; plus, Unit 1's annual NOx ton per year potential to emit based on 5,000 h/yr gas firing at 15 ppm and 1,000 h/yr of fuel oil firing at 42 ppm.

Based on the aforementioned formula, the NOx emission cap for Units 1 & 2 will equal 377.1 tpy. All calculations and assumptions relevant to the NOx emission cap are included in Attachment H. This is more than a 30 tpy offsetting reduction in NOx emissions from the facility as a whole, compared to permitted levels. As such, with the understanding that Units 1 & 2 will retain their current fuel oil firing capability (i.e., 1,000 h/yr when natural gas is unavailable and 800 h/hr when natural gas is available, per unit), the Applicant is willing to limit the total NOx emissions from Units 1 & 2 to the suggested cap of 377.1 tpy.

If you have any questions regarding this submittal, please do not hesitate to call me at 913-458-7928.

Very truly yours,

BLACK & VEATCH

Timothy M. Hillman
Air Permit Coordinator

kjl
Enclosure[s]

cc: Ben Sharma (KUA)
Jeff Ling (KUA)
Tasha Buford

CC: EPA
NPS
CD
M. Halpin, BAR

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

   Name : A. K. Sharma
   Title : Director of Power Supply

2. Owner or Authorized Representative or Responsible Official Mailing Address :

   Organization/Firm : Kissimmee Utility Authority
   Street Address : 1701 West Carroll Street
   City : Kissimmee
   State : FL Zip Code : 34741-6804

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

   Telephone : (407)933-7777 Fax : (407)847-0787

4. Owner/Authorized Representative or Responsible Official Statement :

   I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*

   AK Sharma 10/26/99
   Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name : D. D. Schultz Registration Number : 30304	
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Street Address : 8400 Ward Parkway City : Kansas City	State : MO Zip Code : 64114-2031
3. Professional Engineer Telephone Numbers : Telephone : (913)458-2028	Fax : (913)458-2934

4. Professional Engineer Statement :

I, the undersigned, hereby certify, except as particularly noted herein, that :*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

D D Schultz — 10/28/99

Signature — Date

(seal) DEAN SCHULTZ CERTIFICATE NO. 30363

ATTACHMENT A

NOx EMISSION SUMMARY for RELATIVE ACCURACY TEST AUDITS
COMBUSTION TURBINE 1
CANE ISLAND PLANT
KISSIMMEE UTILITIES AUTHORITY
INTERCESSION CITY, FLORIDA
NOVEMBER 15, 1995

FIGURE 1 - RELATIVE ACCURACY DETERMINATION(NOx)

RUN NO.	TIME	NOx PPM @ 15% O2			CT LOAD	NOx LB/MMBTU		
		RM	M	DIFF	MW	RM	M	DIFF
1	0750-0814	22.19	22.39	-0.2	40.0	0.082	0.082	0
2	0837-0901	23.7	22.89	0.81	40.0	0.087	0.084	0.003
3	0909-0933	23.58	23.65	-0.07	40.0	0.087	0.087	0
4	0945-1009	24.32	23.95	0.37	40.0	0.09	0.088	0.002
5	1016-1040	23.94	23.41	0.53	40.0	0.088	0.086	0.002
6	1047-1111	22.99	22.97	0.02	40.0	0.084	0.085	-0.001
7	1121-1145	23.89	23.12	0.77	39.8	0.088	0.085	0.003
8	1152-1216	23.6	23.08	0.52	39.9	0.087	0.085	0.002
9	1224-1248	23.54	23.08	0.46	39.7	0.086	0.085	0.001

TOTAL DATA POINTS:			9			9
AVERAGE :	23.53	23.17	0.357	0.0866	0.0852	0.0013
Sd:			0.362			0.0014
CC:			0.278			0.0011
RA:			**2.70**			**2.80**
BAF(BIAS ADJUSTMENT):			1.015			1.016

Table 1 Emission Summary
Units 1 and 2
Cane Island Facility
Kissimmee Utility Authority
Intercession City, Florida
October 8-9, 1996

Unit 1 - Number 2 Diesel Firing - October 9, 1996

Run No.	Time	Actual Heat Input GPM	MMBTUH HHV	O2%	NOx Emissions ppmvd	15% O2 ppmvd	ISO ppmvd	lbs/MMBTU	l
1	0952-1059	38.1	315.61	14.92	38.12	37.59	44.47	0.147	4
2	1122-1231	38.7	320.6	14.65	38.71	36.55	44.19	0.142	4
3	1245-1352	44.1	365.3	14.92	37.99	37.49	46.00	0.146	5
Average		40.3	333.8	14.83	38.27	37.21	44.89	0.145	4

Unit 1 - Natural Gas Firing - October 9, 1996

Run No.	Time	Actual Heat Input KSCFH	MMBTUH HHV	O2%	NOx Emissions ppmvd	15% O2 ppmvd	ISO ppmvd	lbs/MMBTU	ll
1	1458-1648	339.85	354.3	15.41	22.82	24.5	29.97	0.090	3
2	1701-1845	339.85	354.3	15.33	23.02	24.39	29.18	0.090	3
3	1857-2024	359.04	374.3	15.39	23.06	24.68	30.46	0.091	3
Average		346.25	361.0	15.38	22.97	24.52	29.87	0.090	3

Unit 2 - Natural Gas Firing - October 8, 1996

Run No.	Time	Actual Heat Input KSCFH	MMBTUH HHV	O2%	NOx Emissions ppmvd	15% O2 ppmvd	ISO ppmvd	lbs/MMBTU	lb
1	1405-1512	800	834	15.08	7.89	7.99	10.02	0.030	24
2	1532-1639	810	844	15.01	7.91	7.93	10.04	0.029	24
3	1653-1800	815	850	15.12	8.06	8.23	9.90	0.030	25
Average		808	843	15.07	7.95	8.05	9.99	0.030	24

NOTES: ISO = emissions at 59°F, 40% RH, 29.92" Hg
HHV Oil = 138064 BTU/Gal
HHV Gas = 1042.5 BTU/SCF

$$\text{lbs/MMBTU} = \text{ppm } (2.595 \times 10\text{-}9)(M)(Fd)\left(\frac{20.9}{20.9 - \%O2}\right)$$

lbs/Hr = lbs/MMBTU x MMBTUH

TABLE 1 - NOx RATA RESULTS
COMBUSTION TURBINE CT-1
KISSIMMEE UTILITIES AUTHORITY
CANE ISLAND PLANT
10/16/97
NATURAL GAS FIRING

RELATIVE ACCURACY DETERMINATION(NOx/DILUENT)

RUN NO.	TIME	REFERENCE METHOD			NOx COMBINED SYSTEM(LB/MMbtu)		
		NOx PPM	O2 %	LB/MMbtu	RM	M	DIFF
1	1007-1037	22.61	15.27	0.087	0.087	0.077	0.010
2	1047-1117	21.15	15.24	0.081	0.081	0.074	0.007
3	1132-1202	20.99	15.23	0.080	0.080	0.074	0.006
4	1210-1240	21.19	15.22	0.081	0.081	0.075	0.006
5	1253-1323	21.50	15.24	0.083	0.083	0.077	0.006
6	1331-1401	22.36	15.23	0.086	0.086	0.076	0.010
7	1410-1434	22.87	15.32	0.089	0.089	0.077	0.012
8	1441-1505	21.82	15.25	0.084	0.084	0.078	0.006
9	1514-1536	21.56	15.17	0.082	0.082	0.077	0.005

TOTAL DATA POINTS:			9			9
AVERAGE DIFF. :	21.78	15.24	0.084	0.084	0.076	0.008
Sd:						0.002
CC:						0.002
RA:						11.29
BAF(BIAS ADJUSTMENT):						1.099

TABLE 1 - NOx RATA RESULTS
COMBUSTION TURBINE CT-1
KISSIMMEE UTILITIES AUTHORITY-CANE ISLAND
INTERCESSION CITY, FLORIDA
10/6/98
NATURAL GAS FIRING

RELATIVE ACCURACY DETERMINATION(NOx/DILUENT)

RUN NO.	TIME	REFERENCE METHOD			NOx COMBINED SYSTEM(LB/MMbtu)		
		NOx PPM	O2 %	LB/MMbtu	RM	M	DIFF
1	1025-1045	21.53	14.64	0.075	0.075	0.079	-0.004
2	1059-1119	20.33	14.75	0.072	0.072	0.081	-0.009
3	1130-1150	19.90	14.69	0.070	0.070	0.082	-0.012
4	1205-1225	22.02	14.71	0.077	0.077	0.083	-0.006
5	1235-1255	20.82	14.72	0.073	0.073	0.083	-0.010
6	1309-1329	20.30	14.77	0.072	0.072	0.083	-0.011
7	1346-1406	21.71	14.76	0.077	0.077	0.083	-0.006
8	1418-1438	21.65	14.70	0.076	0.076	0.083	-0.007
9	1448-1508	22.20	14.71	0.078	0.078	0.083	-0.005
TOTAL DATA POINTS:				9			9
AVERAGE DIFF. :		21.16	14.72	0.074	0.074	0.082	-0.008
Sd:							0.003
CC:			PASSED WITH AVERAGE DIFFERENCE < 0.01				0.002
RA:							13.36
BAF(BIAS ADJUSTMENT):							1.000

ATTACHMENT B

October 12,1999
Unit 1

	NOx_cor_1	H2O_INJ_1	GAS_FL_1	LOAD_1	Gas pph	H2o pph	water to gas ratio
16:30	21.7	27.44	5228	30	14220.9212	13730.976	0.965547577
16:31	21.5	27.39	5219	30.01	14196.43989	13705.956	0.965450219
16:32	24.3	27.55	5218	30.01	14193.71974	13786.02	0.971276047
16:33	20.9	27.63	5224	30.06	14210.04061	13826.052	0.972977655
16:34	21.2	27.83	5223	30.02	14207.32047	13926.132	0.980208198
16:35	21	27.79	5227	30.01	14218.20105	13906.116	0.978050314
16:36	20.9	27.45	5225	30.01	14212.76076	13735.98	0.966454036
16:37	21.4	28.04	5220	30.03	14199.16003	14031.216	0.988172256
16:38	20.9	27.54	5216	30.04	14188.27945	13781.016	0.971295783
16:39	21.2	27.68	5230	30.01	14226.36149	13851.072	0.973620136
16:40	21.1	28.11	5222	30.06	14204.60032	14066.244	0.990259752
16:41	20.8	27.71	5224	30.01	14210.04061	13866.084	0.975794818
16:42	21.2	27.91	5223	30	14207.32047	13966.164	0.983025901
16:43	20.7	30.36	5610	33.09	15260.01682	15192.144	0.995552245
16:44	22.9	32.81	5781	33.94	15725.16171	16418.124	1.044067101
16:45	20.9	31.94	5785	33.89	15736.0423	15982.776	1.015679527
16:46	21.9	32.35	5778	33.81	15717.00128	16187.94	1.02996365
16:47	21.1	32.24	5775	33.84	15708.84084	16132.896	1.026994682
16:48	21.5	32	5778	33.84	15717.00128	16012.8	1.018820303
16:49	21.6	32.45	5782	33.85	15727.88186	16237.98	1.03243273
16:50	21.1	32.1	5774	33.88	15706.12069	16062.84	1.02271212
16:51	21.5	32.64	5779	34.02	15719.72142	16333.056	1.039016886
16:52	21.2	32.21	5785	34.05	15736.0423	16117.884	1.024265422
16:53	21.5	32.77	5777	33.99	15714.28113	16398.108	1.043516268
16:54	21.1	31.82	5762	33.86	15673.47895	15922.728	1.015902599
16:55	21.9	32.6	5766	33.8	15684.35953	16313.04	1.040083273
16:56	21	32.04	5764	33.81	15678.91924	16032.816	1.022571502
16:57	21.4	32.13	5779	33.86	15719.72142	16077.852	1.022782247
16:58	21.5	32.31	5768	33.81	15689.79982	16167.924	1.030473568
16:59	21.4	32.32	5777	33.89	15714.28113	16172.928	1.029186627
17:00	21.4	32.49	5778	33.94	15717.00128	16257.996	1.034420989
17:01	21.4	32.41	5775	33.89	15708.84084	16217.964	1.032409976
17:02	51.8	32.95	5773	33.92	15703.40055	16488.18	1.049975128
17:03	20.2	33	5774	33.88	15706.12069	16513.2	1.051386292
17:04	20.5	32.16	5775	33.89	15708.84084	16092.864	1.024446308
17:05	21.3	32.69	5773	33.93	15703.40055	16358.076	1.041690043
17:06	20.9	32.58	5770	33.94	15695.24011	16303.032	1.0387246
17:07	21.3	32.38	5775	33.85	15708.84084	16202.952	1.031454336
17:08	21.1	32.33	5744	33.75	15624.51633	16177.932	1.0354197
17:09	21.1	32.23	5767	33.84	15687.07968	16127.892	1.028100343
17:10	21.3	32.41	5770	33.78	15695.24011	16217.964	1.033304612
17:11	21.1	32.04	5734	33.76	15597.31487	16032.816	1.027921545
17:12	21.4	32.68	5741	33.77	15616.35589	16353.072	1.04717593
17:13	20.7	32.31	5746	33.72	15629.95662	16167.924	1.034418994
17:14	21	32.3	5740	33.71	15613.63574	16162.92	1.035179779
17:15	21	31.95	5736	33.7	15602.75516	15987.78	1.024676721
17:16	21.2	32.41	5725	33.7	15572.83356	16217.964	1.041426657
17:17	20.8	32.55	5747	33.77	15632.67676	16288.02	1.041921371
17:18	20.8	32.15	5754	33.91	15651.71778	16087.86	1.027865454
17:19	21.5	32.91	5758	33.92	15662.59836	16468.164	1.051432439

17:20	20.6	32.68	5773	33.92	15703.40055	16353.072	1.041371386
17:21	20.8	32.51	5757	33.84	15659.87822	16268.004	1.038833366
17:22	21	32.34	5758	33.76	15662.59836	16182.936	1.033221668
17:23	21.1	32.06	5721	33.66	15561.95298	16042.824	1.030900429
17:24	21	32.09	5714	33.58	15542.91196	16057.836	1.033129187
17:25	21.1	31.94	5714	33.55	15542.91196	15982.776	1.028299976
17:26	21	32.12	5713	33.52	15540.19181	16072.848	1.034276037
17:27	20.9	32.12	5721	33.61	15561.95298	16072.848	1.03282975
17:28	21	32.45	5740	33.77	15613.63574	16237.98	1.039987116
17:29	20.8	32.4	5756	33.76	15657.15807	16212.96	1.035498264
17:30	20.9	32.52	5751	33.77	15643.55735	16273.008	1.040237054
17:31	21	32.16	5759	33.77	15665.31851	16092.864	1.027292486
17:32	33.1	31.74	5735	33.74	15600.03502	15882.696	1.018119253
17:33	21.4	31.77	5749	33.7	15638.11705	15897.708	1.016599885
17:34	21.4	32.23	5753	33.79	15648.99764	16127.892	1.030602239
17:35	20.9	32.1	5761	33.92	15670.7588	16062.84	1.025019924
17:36	21.7	32.48	5773	33.95	15703.40055	16252.992	1.034998244
17:37	21.1	32.41	5778	33.97	15717.00128	16217.964	1.031873938
17:38	21.3	32.11	5775	33.91	15708.84084	16067.844	1.022853574
17:39	21.5	32.4	5776	33.93	15711.56099	16212.96	1.031912743
17:40	21.3	32.56	5782	33.97	15727.88186	16293.024	1.035932502
17:41	21.1	32.22	5784	33.96	15733.32215	16122.888	1.024760559
17:42	21.6	31.92	5775	33.83	15708.84084	15972.768	1.016801186
17:43	21.4	32.06	5757	33.78	15659.87822	16042.824	1.024453944
17:44	21.4	32.18	5774	33.81	15706.12069	16102.872	1.025260936
17:45	21.2	32.19	5766	33.8	15684.35953	16107.876	1.027002471
17:46	21.3	32.17	5757	33.77	15659.87822	16097.868	1.027968914
17:47	21.2	32.21	5770	33.87	15695.24011	16117.884	1.026928157
17:48	21.4	32.42	5784	33.92	15733.32215	16222.968	1.03112158
17:49	21.3	32.67	5790	33.89	15749.64302	16348.068	1.037996098
17:50	20.9	32.02	5753	33.9	15648.99764	16022.808	1.023887176
17:51	21.2	32.47	5761	33.83	15670.7588	16247.988	1.036834796
17:52	21	32.23	5757	33.9	15659.87822	16127.892	1.02988617
17:53	21.2	32.62	5793	33.95	15757.80346	16323.048	1.03587077
17:54	20.9	32.3	5778	33.97	15717.00128	16162.92	1.028371743
17:55	21.3	32.56	5801	33.99	15779.56463	16293.024	1.032539515
17:56	21.1	32.77	5796	33.99	15765.9639	16398.108	1.040095493
17:57	20.8	32.08	5787	33.93	15741.48259	16052.832	1.019778913
17:58	21.3	32.68	5786	33.88	15738.76244	16353.072	1.03903163
17:59	20.7	31.76	5759	33.79	15665.31851	15892.704	1.014515216
18:00	21.3	32.51	5760	33.8	15668.03866	16268.004	1.038292307
18:01	20.7	32.22	5776	33.82	15711.56099	16122.888	1.026179895
18:02	45.4	32.08	5759	33.81	15665.31851	16052.832	1.024737032
18:03	20.5	31.92	5754	33.75	15651.71778	15972.768	1.020512139
18:04	20.6	32.56	5758	33.76	15662.59836	16293.024	1.040250386
18:05	20.3	32.74	5764	33.91	15678.91924	16383.096	1.044912328
18:06	20.5	32.52	5766	33.85	15684.35953	16273.008	1.037530922
18:07	20.4	32.55	5764	33.79	15678.91924	16288.02	1.03884839
18:08	20.5	32.79	5772	33.79	15700.6804	16408.116	1.045057639
18:09	20.4	32.61	5772	33.94	15700.6804	16318.044	1.039320818
18:10	20.5	32.82	5776	33.96	15711.56099	16423.128	1.04528939
18:11	20.6	32.52	5776	33.87	15711.56099	16273.008	1.035734642
18:12	20.9	32.62	5783	33.95	15730.602	16323.048	1.037662004
18:13	20.6	32.65	5791	33.97	15752.36317	16338.06	1.037181522
18:14	20.7	32.43	5792	34.06	15755.08332	16227.972	1.030014991
18:15	20.9	32.8	5797	34.04	15768.68404	16413.12	1.040868087

18:16	20.7	32.53	5764	33.95	15678.91924	16278.012	1.03821008
18:17	20.6	32.68	5765	33.87	15681.63938	16353.072	1.042816481
18:18	20.5	32.06	5776	33.97	15711.56099	16042.824	1.021084029
18:19	21	32.6	5783	34.03	15730.602	16313.04	1.037025792
18:20	20.6	32.5	5787	34.08	15741.48259	16263	1.033130133
18:21	20.8	32.71	5819	34.17	15828.52725	16368.084	1.034087616
18:22	20.9	32.5	5810	34.17	15804.04594	16263	1.029040289
18:23	21	32.65	5800	34.17	15776.84448	16338.06	1.035572102
18:24	21	32.74	5811	34.13	15806.76608	16383.096	1.036460963
18:25	21	32.41	5796	34.07	15765.9639	16217.964	1.02866936
18:26	21	32.44	5795	34.01	15763.24375	16232.976	1.029799212
18:27	21.1	32.47	5787	33.97	15741.48259	16247.988	1.032176474
18:28	21	32.76	5795	34.06	15763.24375	16393.104	1.039957528
18:29	20.7	32.55	5794	34.06	15760.52361	16288.02	1.033469471
18:30	20.8	32.8	5798	34.15	15771.40419	16413.12	1.040688565
18:31	20.9	32.87	5814	34.19	15814.92652	16448.148	1.040039483
18:32	4.7	33.01	5807	34.21	15795.8855	16518.204	1.045728269
18:33	17.5	33.17	5809	34.2	15801.32579	16598.268	1.050435148
18:34	20.2	32.28	5821	34.26	15833.96754	16152.912	1.020143054
18:35	21.3	32.66	5822	34.27	15836.68768	16343.064	1.031974888
18:36	20.9	32.71	5822	34.24	15836.68768	16368.084	1.033554764
18:37	21	32.48	5807	34.24	15795.8855	16252.992	1.028938327
18:38	21.3	32.89	5840	34.26	15885.6503	16458.156	1.036039173
18:39	20.8	32.87	5817	34.26	15823.08696	16448.148	1.039503104
18:40	21.1	32.63	5810	34.21	15804.04594	16328.052	1.03315645
18:41	21.2	32.71	5813	34.32	15812.20637	16368.084	1.035154969
18:42	21.4	32.99	5839	34.3	15882.93016	16508.196	1.039367159
18:43	21.1	32.76	5835	34.33	15872.04958	16393.104	1.032828427
18:44	21.2	33.03	5815	34.25	15817.64666	16528.212	1.044922317
18:45	21	33.13	5816	34.24	15820.36681	16578.252	1.047905665
18:46	20.9	32.67	5818	34.23	15825.8071	16348.068	1.033000585
18:47	21.3	32.5	5820	34.27	15831.24739	16263	1.027272179
18:48	21.4	32.78	5823	34.28	15839.40783	16403.112	1.035588715
18:49	21.4	32.68	5826	34.23	15847.56827	16353.072	1.031897874
18:50	21.4	32.6	5825	34.28	15844.84812	16313.04	1.029548524
18:51	21.4	32.77	5821	34.27	15833.96754	16398.108	1.035628497
18:52	21.3	32.8	5834	34.26	15869.32943	16413.12	1.034266764
18:53	21.4	32.68	5820	34.27	15831.24739	16353.072	1.032961686
18:54	20.8	32.35	5825	34.21	15844.84812	16187.94	1.021653214
18:55	21.1	32.67	5822	34.25	15836.68768	16348.068	1.032290863
18:56	20.8	32.49	5818	34.21	15825.8071	16257.996	1.027309122
18:57	21	32.6	5822	34.24	15836.68768	16313.04	1.030079037
18:58	20.8	32.55	5813	34.24	15812.20637	16288.02	1.030091539
18:59	21.1	32.55	5809	34.26	15801.32579	16288.02	1.030800846
19:00	20.9	32.65	5825	34.29	15844.84812	16338.06	1.031127586
19:01	20.9	32.24	5813	34.3	15812.20637	16132.896	1.020281144
19:02	50.9	32.53	5812	34.29	15809.48623	16278.012	1.029635737
19:03	20.8	32.63	5814	34.34	15814.92652	16328.052	1.032445644
19:04	20.9	32.06	5829	34.37	15855.7287	16042.824	1.011799855
19:05	21.5	32.49	5825	34.33	15844.84812	16257.996	1.026074588
19:06	21.1	32.27	5825	34.26	15844.84812	16147.908	1.019126714
19:07	21.2	32.6	5816	34.31	15820.36681	16313.04	1.031141705
19:08	20.9	32.16	5829	34.31	15855.7287	16092.864	1.014955812
19:09	21.3	32.46	5831	34.29	15861.16899	16242.984	1.024072312
19:10	21.2	32.76	5830	34.32	15858.44885	16393.104	1.033714215
19:11	21	32.27	5843	34.43	15893.81074	16147.908	1.015987183

19:12	22.1	32.93	5861	34.46	15942.77336	16478.172	1.033582528
19:13	21.5	32.93	5859	34.48	15937.33307	16478.172	1.033935347
19:14	21.8	32.67	5865	34.49	15953.65394	16348.068	1.02472249
19:15	21.9	33.11	5862	34.49	15945.49351	16568.244	1.039054953
19:16	21.5	32.66	5861	34.47	15942.77336	16343.064	1.025107968
19:17	21.3	32.93	5844	34.37	15896.53089	16478.172	1.036589185
19:18	21.1	32.19	5847	34.42	15904.69132	16107.876	1.012775141
19:19	21.9	32.92	5852	34.46	15918.29205	16473.168	1.034857757
19:20	21	32.74	5859	34.54	15937.33307	16383.096	1.027969732
19:21	21.2	32.94	5874	34.57	15978.13525	16483.176	1.031608241
19:22	21.1	32.63	5861	34.49	15942.77336	16328.052	1.02416635
19:23	21.2	33.06	5860	34.47	15940.05322	16543.224	1.037839948
19:24	20.9	32.47	5852	34.4	15918.29205	16247.988	1.020711767
19:25	21.5	32.94	5857	34.4	15931.89278	16483.176	1.034602494
19:26	20.9	32.42	5855	34.38	15926.45249	16222.968	1.0186178
19:27	21.4	32.76	5852	34.41	15918.29205	16393.104	1.029828071
19:28	21.1	32.71	5849	34.45	15910.13161	16368.084	1.028783696
19:29	21.1	32.73	5850	34.4	15912.85176	16378.092	1.029236761
19:30	21.1	32.94	5845	34.42	15899.25103	16483.176	1.036726571
19:31	21	32.72	5850	34.51	15912.85176	16373.088	1.028922298
19:32	1.7	32.49	5863	34.56	15948.21365	16257.996	1.019424266
19:33	21.2	32.53	5878	34.66	15989.01584	16278.012	1.018074669
19:34	21.4	32.84	5873	34.6	15975.41511	16433.136	1.02865158
19:35	21.1	32.73	5868	34.52	15961.81438	16378.092	1.026079593

	NOx ppm			Load (MW)	Gas Usage (lb/h)	Water Usage (lb/h)	Water-to-Fuel
1	21.43	32.15	5753.08	33.77	15649.22	16086.89	1.03
2	21.91						

Note

1 Including all data

2 Rolling 1-hour average

ATTACHMENT C

GE Industrial AeroDerivative
Gas Turbines

GE Power Systems.
One Neumann Way, S158
Cincinnati, OH 45215-1988
Phone: (513) 552-5925
Fax: (513) 552-5059

October 19, 1999

KUA

Attn: Larry Mattern

The purpose of this letter is to

- Respond to your inquiry regarding high water injection rates
- Provide response on the use of spray intercooling on the KUA units

High Water Injection Rates

GE currently offers LM6000PC with water injection for NOx abatement to levels of 25 ppm NOx. At ISO conditions, the expected water : fuel ratio for a typical natural gas fuel is 1.18. With engine-to-engine variation, the water : fuel requirements can be as high as 1.42 to achieve this NOx level.

GE recommends that water should not be injected beyond that required to achieve 25 ppm NOx, and, in no case, beyond 1.42 water to fuel ratio (without consulting GE). Attempts to oversuppress to levels significantly below 25 ppm will have the following consequences and added risks:

- Reduced combustor venturi life and need for more frequent inspections. Expected venturi life is 25000 hours on natural gas with water suppression to 42 ppm. Expected life of the same combustor is 16000 hours at 25 ppm. Erosion life is believed to be very non linear, therefore suppressing to <<25 will result in significantly lower erosion life and increased maintenance costs and reduced availability.
- Oversuppressing *will add risk* in terms of combustor stability and could cause high combustor dynamic pressures which will result in distress of combustion system components.

High Water Injection Rates

GE currently offers spray intercooling, also known as SPRINT™, exclusively on the LM6000PC. While there have been several inquiries relative to use of SPRINT™ with LM6000PA, GE does not currently plan to offer this as a product.

GE recently proposed to the FL-DEP that SPRINT™ could be used in conjunction with other new features on two LM6000 PB engines in Bartow FL in order to achieve the permit level of 15 ppm. This will require a development program and engine testing to ensure no adverse consequences result from the water injection levels envisioned for the LM6000PB machines. If the FL-DEP is supportive of this approach we will be conducting tests before end of June 2000 and will have a better idea of the exact benefits on a PB engine.

The intent of the above program is to achieve 15 ppm on the existing LM6000PB engines at the Bartow site. Since the LM6000PB is no longer in production, this system is not intended to be a general product offering at this time.

Best regards,

RB Hook
LM6000 Technical Program Mgr.
GE Industrial Aeroderivative Gas Turbines

Cc: Z Biernacki, D Harmon, C Stump, P Tinne

ATTACHMENT D

GIVEN

Reference 1 - Quote from Engelhard for high temperature SCR to reduce emissions from an LM 6000. Emissions reduction from 22 ppm to 2 ppm.
Reference 4 - Quote from Cormetech for conventional catalyst. Used as a basis for adjusting costs to Cane Island Unit 1 emissions requirements.

CALCULATING AN ADJUSTMENT FACTOR TO BE USED TO ADJUST ENGELHARD QUOTE

Cormatech Data	inlet	outlet	Price	% Removed	(Reference 4)
RATIO 1 (Case 2) for 25 to 4.5 ppm	25	4.5	$504,000	82%	
RATIO 2 (Case 4) for 9 to 2 ppm	25	2	$737,000	92%	

Therefore, to go from 25 TO 4.5 PPM, requires 68 % of the catalyst for reduction from 25 TO 2.0 PPM
68 % = $504000 / $737000 * 100

ADJUSTING ENGELHARD QUOTE

Engelhard Data	inlet	outlet	Price	(Reference 1)
	22	2.5	$1,558,000	

Therefore, 68 % of $1558000 is the catalyst cost = $1,065,444

Plus, need to correct for the difference in inlet NOx.
A unit achieving 92 % (25 to 2) requires 104 % more catalyst than a unit achieving 89 % (22 to 2.5).
104 % = 92 % / 89 % * 100
Therefore, $1065444 * 104 % is the catalyst cost = $1,105,876

Reference 4

p-622-bv-9/16/98

CORMETECH, INC.

ENVIRONMENTAL TECHNOLOGIES

5000 International Drive Durham, NC 27712

TEL 919-620-3000 FAX 919-620-3001

If not received properly, call 919-620-3000

Number of pages including cover: 7 **Reference Number:** 98 1267

TO: Rick Lausman
BLACK & VEATCH
Overland Park, KS

7528
P461

TEL 913-458-7528
FAX 913-458-2934

CC: Nancy Stephenson

FROM: Elizabeth Mancini

DATE: 9/16/98

SUBJECT: SCR Catalyst Budgetary Quotation
General Information

REFERENCE:
1. Cormetech Reference Number CM622
2. Fax from Rick Lausman/BV to Elizabeth Mancini/Cormetech 9/10/98

We are pleased to submit our budgetary quotation to supply SCR catalyst for the above subject project. Budgetary indicates ± 10%. If you have any questions or require additional information, please contact me at 919-620-3022.

Best regards,

EMa

Proposals/bv/bvgeninfo.doc:CM622

Best Available Copy

Fax to Rick Lausman/BV from Elizabeth Mancini/Cormetech
RE: SCR Catalyst Budgetary Quotation: General Information

Scope of Supply:

- Catalyst Design, Supply, and Assembly
- Patent and License Indemnification
- Module Engineering and Supply
- Initial Pilot Test
- Sample Module for Easy Catalyst Sample Retrieval

Catalyst:

	Case 1
Catalyst	CM-27™
Pitch, mm	2.7
Gas Flow Orientation	Horizontal

Modules:

	Case 1	Case 2	Case 3	Case 4
Number/Unit	24	24	24	24
Number of Layers	1	1	1	1
Arrangement/Layer	$3_w \times 8_h$	$3_w \times 8_h$	$3_w \times 8_h$	$3_w \times 8_h$
Dimensions, in each	$127.375_w \times 66.375_h \times 16_d$	$103.125_w \times 66.375_h \times 14_d$	$127.375_w \times 66.375_h \times 16_d$	$127.375_w \times 66.375_h \times 20_d$
Weight, lbs each	2400	1800	2400	2900
Material	Carbon Steel	Carbon Steel	Carbon Steel	Carbon Steel

Price:

	Case 1	Case 2	Case 3	Case 4
Price, 1 Unit(s)	$304,000	$200,000	$313,000	$433,000
FOB	Durham			
Delivery	6 - 9 mo ARO			
Validity from date of this proposal	90 days			
Payment Terms	Net 30 days			
Invoice Schedule	30% upon Order; 70% upon Delivery			
[illegible] % NO_x [illegible]	67.5	53.1	68.8%	79.2%

CORMETECH CONFIDENTIAL

Fax to Rick Lausman/BV from Elizabeth Mancini/Cormetech
RE: SCR Catalyst Budgetary Quotation: General Information

Guarantee Performance*:

	Case 1	Case 2	Case 3	Case 4
NOx Outlet, ppmvd @ 15% O_2	≤ 9	≤ 4.5	≤ 3.0	≤ 2.0
NH_3 Slip, ppmvd @ 15% O_2	≤ 10	≤ 10	≤ 10	≤ 10
Δp Across Catalyst, in wg	≤ 1.8	≤ 2.0	≤ 1.8	≤ 2.5
Design Life	The earlier of 36 months from first gas-in or 39 months from contracted delivery			

*Guarantee performance is based on the attached Cormetech, Inc. Catalyst Technical Terms and Conditions and the following:

1. Maldistribution criteria:
   Flow ± 15% RMS; Temperature ± 20°F; NH_3:NOx Molar Ratio ± 5% RMS.

Design Flue Gas Conditions:

	Case 1	Case 2	Case 3	Case 4
Fuel	Gas	Gas	Gas	Gas
Flue Gas Flow Rate, lb/hr	3,474,000	3,474,000	3,474,000	3,474,000
Design Temperature, °F	650	650	650	650
Flue Gas Composition				
N_2, vol %	73.7	73.7	73.7	73.7
O_2, vol %	9.43	9.43	9.43	9.43
CO_2, vol %	5.2	5.2	5.2	5.2
H_2O, vol %	10.75	10.75	10.75	10.75
Ar, vol %	0.92	0.92	0.92	0.92
O_2, vol % dry	10.57	10.57	10.57	10.57
Inlet NOx, ppmvd @ 15% O_2	27.7	9.6	9.6	9.6
NOx lb/hr	243	84.7	84.7	84.7

General Terms and Conditions:
Cormetech, Inc. General Terms and Conditions of Sale, attached.

CORMETECH, INC.
Catalyst Technical Terms and Conditions

Warranty Conditions

1. Unit operating conditions shall be within the limits of design cases specified in SCR Catalyst Quotation.

2. The catalysts must be handled, operated, and maintained according to Cormetech instruction.

3. Cormetech maintains warranty protection as long as normal furnace start-up and shut-down procedures are followed and no moisture other than from flue gas or ambient air is present. The allowed start-up and shut-down temperature gradient for the catalyst is 10°C/min below and 60°C/min above the flue gas dew point.

4. Catalyst has been designed to accommodate profile maldistributions, based on a Normal Distribution, per SCR Catalyst Quotation.

5. Cormetech is not responsible for catalyst deterioration caused by aqueous ammonia drainage or water contact to the catalyst.

6. Suitable means must be employed, if needed, to clean catalyst masked or plugged by firing of particulate producing fuel. Customer will inspect visually at shutdowns and clean, as needed.

7. Access must be provided to Cormetech for visual inspection and catalyst sampling. Cormetech reserves the right to review the Unit's operating data at any time during the warranty period.

8. Customer must provide catalyst samples to Cormetech no less than annually during the warranty period, in order to maintain warranties.

9. Customer will provide a copy of all procedures and methods of analysis to be employed in catalyst evaluation for Acceptance and anytime throughout the warranty period.

Warranty Fulfillment

1. Cormetech's warranties are fulfilled at the end of the period stated in SCR Catalyst Quotation if the results of on-site tests indicates that the performance values, shown in SCR Catalyst Quotation, are met.

2. If the results of on-site tests during the warranty period indicates that the warranted values are not being met, Customer will conduct an on-site investigation to determine the cause of non-performance. If the catalyst is suspect, Cormetech will conduct laboratory tests, according to the conditions specified in SCR Catalyst Quotation, to verify the catalyst performance.

3. If the results of the laboratory tests indicate that the warranted values are being met, Cormetech's warranties will be deemed in fulfillment at this time and Customer will continue their investigation to determine the cause of non-fulfillment. Customer will compensate Cormetech for the cost of laboratory evaluation.

4. If the results of the laboratory tests indicate that the warranty values are not being met, Cormetech will, at its option, repair, replace, or add catalyst at its cost to meet the required performance values. Cormetech will absorb cost of laboratory evaluation.

CORMETECH, INC.
General Terms and Conditions of Sale

1. DEFINITIONS:
"Buyer" means the firm or company which places the order and purchases the Goods from Seller.
"Seller" means Cormetech, Inc.
"Goods" means the SCR Catalyst to be purchased by the Buyer.
"Order" means the purchasing order placed by the Buyer for the supply of the Goods.
"Specifications" means Seller's written technical description of the Goods purchased pursuant to the Order therefor and Seller's acceptance thereof.
"Owner" means the person, firm or company to whom the Buyer furnishes the plant including the Goods supplied by the Seller.

2. CONTRACT:
The contract for the purchase and sale of Goods shall be deemed to have been entered into by and between the Buyer and the Seller when, upon receipt of the Buyer's Order for such Goods, the Seller sends an acceptance in writing, within the time limit for such acceptance specified in such Order, executed by the duly authorized representative of Seller. Neither the Buyer nor the Seller shall be bound by any variation, waiver of, or addition to these general terms and conditions unless otherwise agreed by both parties in a writing executed by their duly authorized representatives. Except as otherwise provided in an express written agreement, these general terms and conditions shall govern in the event of any conflict with any terms or conditions proposed by the Seller or Buyer whether or not contained in any order or acceptance, or applicable in previous transactions, practice or course of dealings.

3. LIAISON PERSONNEL:
The Seller, immediately upon receiving Buyer's Order for Goods, may appoint an appropriate person for the performance of Seller's obligation to Buyer with respect to the Goods, to whom all communication thereon shall be directed.

4. DELIVERY:
The method of packing of the Goods shall be in accordance with the agreement of the Buyer and Seller and if no agreement has been reached, the Seller shall take all reasonable steps to prevent damage to or deterioration of the Goods in transit to their destination as specified in the accepted order.
The purchase price for Goods sold pursuant to an accepted purchase order shall include the cost of packing as mentioned above.

5. WARRANTY, QUALITY AND DESCRIPTION:
Seller hereby warrants to Buyer that at the time of delivery, the Goods sold to Buyer will conform to the written specifications set forth in Catalyst Technical Terms and Conditions to acceptable quality levels normally supplied by Seller in connection with the sales of said Goods. Seller will, solely at its option, repair or replace Goods which fail to meet the Terms and Conditions of this limited warranty.
In addition, Seller warrants that the performance of the Goods will, under the conditions specified in Catalyst Technical Terms and Conditions for the period set forth therein meet the performance criteria under the conditions specified therein. Verification of such performance guarantee will be accomplished as specified in Catalyst Technical Terms and Conditions, through the use of laboratory tests.
In the absence of specific alternate language, warranty period is on a calendar basis and begins at first gas-in and no later than three (3) months after scheduled delivery. Specific warranty period and terms are as set forth in the Catalyst Technical Terms and Conditions.
In the event Goods are stored and handled between the time of delivery and installation, Buyer shall provide adequate and appropriate facilities for storage of the Goods. Goods shall be handled according to Seller's Catalyst Handling Manual.
THE FOREGOING WARRANTY AND THE WARRANTY SET FORTH IN SECTION (15) ARE IN LIEU OF ALL OF THE WARRANTIES EXPRESSED OR IMPLIED, INCLUDING, BUT NOT LIMITED TO, IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

6. SPECIFICATIONS:
The Goods sold hereunder shall comply with the written specifications set forth in Catalyst Technical Terms and Conditions. The performance of such Goods will vary in accordance with individual specifications, operation, and maintenance of the systems in which they are installed. Buyer has the sole responsibility for the completeness and accuracy of information. Seller will rely exclusively on such information to make recommendations on the type and volume of Goods to be used in Owner's facility.

7. **MODIFICATION IN SPECIFICATIONS:**
The specifications may be modified and/or changed at any time provided that both the parties agree in writing. Such agreement may include reasonable adjustments of the price, time of delivery of the Goods and other terms before such modifications and/or changes are carried out.

8. **DRAWINGS:**
Drawings, such as, drawings for approval, drawings for installation, drawings showing the finished conditions of the Goods, instruction manuals, etc., shall be supplied by the Seller to the Buyer strictly in accordance with and by the time instructed in the Specification or in the accepted order.

9. **INSPECTION AND TEST AT SELLER'S WORKS**
Upon reasonable notice and at reasonable times, the Buyer shall have access to the office of the Seller or, subject to written consent of such supplier, the office and manufacturing operations of Seller's supplier for expedition of manufacturing or inspection of the Goods in the course of a normal working day during the period from the date of the Order to the date of shipment of the Goods. If such inspection shall be done at the factory of Seller's supplier, the Seller shall also inform the Buyer of the details of such visit in advance. Buyer shall inspect all Goods within thirty (30) days of delivery of such Goods and immediately report to Seller in writing any claims for breach of warranty set forth in Section (5) above. All Goods which remain uninspected after such thirty (30) days shall be deemed accepted by Buyer.
In the event that the Goods are rightfully rejected at the time of inspection for failure to conform to the provisions of Section (5) above, the Seller shall, solely at the Seller's option, repair or replace such Goods.

10. **PRODUCTION SCHEDULE:**
When requested, the Seller will provide the Buyer with the production schedule setting forth the estimated dates for the issuance schedule of drawings, order of material, fabrication schedule, inspection schedule, if any, for the Goods purchased pursuant to the acceptance order, and during the contractual period, keep the Buyer informed monthly of actual progress in providing the Goods.
In case there is some unexpected factor or occurrence which prevents normal progress of production or manufacturing, the Seller shall inform the Buyer promptly.

11. **SHIPPING INSTRUCTION:**
The Goods subject to Buyer's Order shall be sold FOB Jobsite, unless otherwise indicated, and the Buyer or Seller on Buyer's behalf pursuant to Buyer's instructions will book and arrange appropriate transportation from such site. The Seller shall provide the following information regarding such Goods.

a. Net weight, gross weight, freight tons
b. Measurement of each packing or parcel
c. Number of packages
d. Name of loading port
e. Date of cargo readiness

12. **LIMITATION OF LIABILITY:**
If, owing to force majeure as defined in Section (14) hereof, the Seller is unable to deliver the Goods within ninety (90) days of the delivery time specified in the accepted order for such Goods, then provided that the Seller shall have given Buyer written notice of such force majeure, the Buyer shall grant the Seller extension of time, as may be reasonable, to complete performance.
The liability of the Seller, its supplier, their agents, employees, subcontractors and sub-suppliers with respect to any and all claims arising out of the performance or non-performance of obligations in connection with the design, manufacture, sale, delivery, storage, erection or use of the Goods or the rendition of other services in connection therewith, whether based on contract, warranty, tort (including negligence), strict liability or otherwise, shall not exceed in the aggregate the purchase price for the Goods and shall in no event include: damages for loss of profits or revenue or the loss of use of either; loss by reason of plant shutdown or inability to operate at rated capacity; increased expense of operation of plant or equipment; increased costs of purchasing or providing Goods, equipment, materials, supplies or services; costs of replacement power or capital; claims of Owner's customers; inventory or use charges; or any other incidental or consequential damages of any nature.
This limitation of liability shall prevail over any conflicting or inconsistent provisions contained in any of the documents comprising the contract for the Goods, except to the extent such conflicting or inconsistent provisions further restrict the Seller's liability.

13. PRICE AND PAYMENT:
All payments shall be made within thirty (30) days after the presentation of the invoice therefor, unless otherwise indicated.
Seller will meet delivery schedule required by contract. In the event Buyer delays requested delivery, terms of payment shall commence per original schedule. Seller shall notify Buyer of all resultant fees and requirements due to delay, including but not limited to, handling, storage, and truck cancellation fees. Buyer shall be invoiced for said fees upon shipment.
Payments received after date specified on invoice will be assessed a monthly finance charge (12% per annum).

14. FORCE MAJEURE:
Force majeure shall mean unavoidable causes beyond the control of the Seller, including but not limited to, acts of God, war (declared or undeclared), acts of governmental authorities, riot, revolution, civil commotion, fires, strikes (and other labor disputes, sabotege), or epidemic, and other similar matters beyond the reasonable control of a party.
Should the causes of force majeure prevent the total or partial performance required concerning the purchase of Goods, the party claiming force majeure shall promptly advise the other party at the beginning and end of such force majeure and furnish the other party a written notice identifying the nature of the circumstances of force majeure promptly.
In cases of force majeure described above, there shall be consultation between the parties to discuss the effect on the contractual obligations of both parties. For delays and/or non-performance of the obligations due to force majeure, the affected party shall be entitled to an extension of time equal to that of the delay plus such additional time as is reasonably necessary to resume performance of its obligations.

15. PATENTS:
The Seller warrants freedom from patent infringement on those Goods sold under an accepted order when such Goods are used for the purposes normally intended.
Purchase of this product from Cormetech, Inc. includes a license to use this product in the practice of the method claimed in U.S. Patent 4,358,428.

16. ASSIGNMENT:
Neither the contract nor any part of it shall be assigned or transferred to any third party without the other parties' prior written consent where such consent shall not be unreasonably withheld.

17. TAXES:
Any applicable sales, use, excise or other tax shall not be included in Seller's quoted price for Goods.

18. BACKCHARGE:
Seller is not liable, whether by backcharge or otherwise, for the cost of work performed or material or equipment furnished by the Buyer or any third parties unless such work and the costs thereof have been approved in writing by an authorized representative of Seller.

19. NON-DISCLOSURE:
Data, drawings, specifications, or other technical information furnished directly or indirectly, in writing or otherwise, to Seller by Purchaser or to Purchaser from Seller pursuant to this order shall in no event become the property of the receiving party and shall be used only in fulfilling the obligations imposed by this order and shall not be duplicated or disclosed to others or used in whole or in part for any other purpose. Such furnishing of data, drawings, specification, or other technical information shall not be construed as granting any rights whatsoever, express or implied, under patents or privileges of the disclosing party.

20. TERMINATION:
Upon notice, Seller will take all reasonable measures to cease production in-process and to minimize the cost of goods and services procured for fulfillment against this contract. It is recognized that the Goods and Services contracted herein are of custom design and manufacture, the value of which is not reasonably expected to be recoverable by the Seller in the event of termination.
Therefore, upon termination, Seller will submit to Buyer an accounting of all Goods and Services directly allocated to fulfillment of this contract including but not limited to finished Goods, Goods-in-process, non-cancelable subcontracts, and custom dies. Forced disruption of manufacturing in process may result in additional expense which is the sole responsibility of Buyer. It is expected that raw materials may be purchased and production proceed against the requirements of any or all of the defined scope of contract at any time following contract award by Buyer. Seller will keep Buyer informed of progress against contract.

Reference 1

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

FAX NUMBER: 913-458-2934 913-458-2936 913-458-2939

FACSIMILE TRANSMISSION

TO: Mr. Fred Booth
COMPANY: Engelhard
FAX NUMBER: (410) 569-1841
TELEPHONE NUMBER: (410) 569-0297
FROM: Don Wolf
EXTENSION: 2845 LOCATION: P4G1

B&V PROJECT: 063045
B&V PHASE: 0042
B&V FILE:
PAGE: 1 of 2
DATE: June 14, 1999

NOTE TO RECEIVING OPERATOR
In the event of incomplete transmission, please call (913) 458-7218.

TRANSMITTAL DATE/TIME: ______ OPERATOR'S INITIALS: ______

SUBJECT: High Temperature SCR Catalyst for Simple Cycle Combustion Turbines

MESSAGE: As we discussed on the phone this morning Black & Veatch is assessing the experience, feasibility, potential NO_x reductions, and costs for high temperature SCR catalyst located at the outlet of 3 different simple cycle combustion turbines (SCCT).

Please provide the following information:

1. An experience list of Engelhard SCR catalyst applications on SCCT including the inlet and outlet NO_x emissions.
2. A review of the information provided below for the 3 SCCT machines to determine the maximum practical NO_x reduction that can be achieved with high temperature catalyst.
3. Provide cost or catalyst volume (if possible with the limited data and response time).

The 3 SCCTs being evaluated have the general design criteria listed in the table below. Please note that no specific data is available at this time since this is a very cursory review. Therefore, please assume the data below is full load data only.

	GE 7241 (7FA)	GE 7121 (7EA)	GE LM6000 PC Sprint
Exhaust Flow, lb/hr	3,427,200	2,314,800	1,008,000
Exhaust Temperature, F	1,116	998	842
NO_x, ppmvd @ 15% O_2	9	9	22

Please provide the requested information by noon (CST) Tuesday June 15, 1999. If you have any questions please do not hesitate to call me at (913) 458-2845. I appreciate your attention to this matter. Thank you.

P4-1
2845

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	**June 15, 1999**	**NO. PAGES**	**4**	**(INCLUDING COVER)**
TO:	**BLACK & VEATCH** **ATTN: Don Wolf** **ENGELHARD** **ATTN: Nancy Ellison**	**FAX 913-458-2934**		
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**		

RE: **Simple Cycle Turbines**
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB99465

We provide Engelhard Budgetary Proposal EPB99465 for Engelhard **NOxCAT ZNX™** High Temperature SCR Catalyst system components per your FAXed request of June 14, 1999.

Our Budgetary Proposal is based on:

- Gas Turbine operating in simple cycle mode;
- SCR Catalysts for NOx reductions from noted inlet levels to 2.5 ppmvd @ 15% O_2 with ammonia slip of 5 ppmvd @ 15% O_2;
- Nominal 5.0" Delta P across SCR;
- Scope as noted. Please note that we have assumed horizontal gas flow through the SCR reactor and the use of 28% aqueous ammonia.
- Please note that turbine exhaust flow for the GE7FA is cooled with an ambient air injection system to reduce the gas temperature at the SCR to 1,025F. The cost of the components for this turbine is included. The ductwork to hold the catalysts and the transitions and any flow straighteners are not included in scope detailed herein.
- We have indicated cross section area required to meet the conversions and pressure drop. Inside liner width and height can be varied while maintaining same cross sectional area.
- Three (3) Year Performance Guarantee (expected life five to seven years).

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

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

cc: Nancy Ellison - Proposal Administrator

ENGELHARD

Black & Veatch 063045
Simple Cycle Turbines
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99465
June 15, 1999

ENGELHARD CORPORATION
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEMS

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **NOxCAT ZNX™** ceramic substrate SCR system components summarized herein.

NOxCAT ZNX™ High Temperature SCR Catalyst System: **Scope of Supply:** The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **NOxCAT ZNX™** SCR catalyst in modules;
- Internal support structures for catalyst modules (frame);
- Ambient Air injection cooling system components (GE 7FA);
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: 28% Aqueous Ammonia
  Pre-piped & wired (including all valves and fittings) Two (2) dilution air fans, one for back-up purposes
  Panel mounted system controls for:

Blowers (on/off/flow indicators)	Air/ammonia flow indicator and controller
System pressure indicators	Main power disconnect switch

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

BUDGET PRICES: **See Performance Data**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	9,000 hours of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

**Operation is considered to start when exhaust gas is first passed through the catalyst.*

DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation - 10 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Operating manuals
Material Delivery 20 - 24 weeks after approval and release for fabrication

SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbines
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	To 2.5 ppmvd @ 15% O_2
NH3 Slip:	5 ppmvd@15%O_2
Pressure Drop through SCR	Nom. 5"WG

ENGELHARD

Black & Veatch 063045
Simple Cycle Turbines
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99465
June 15, 1999

P

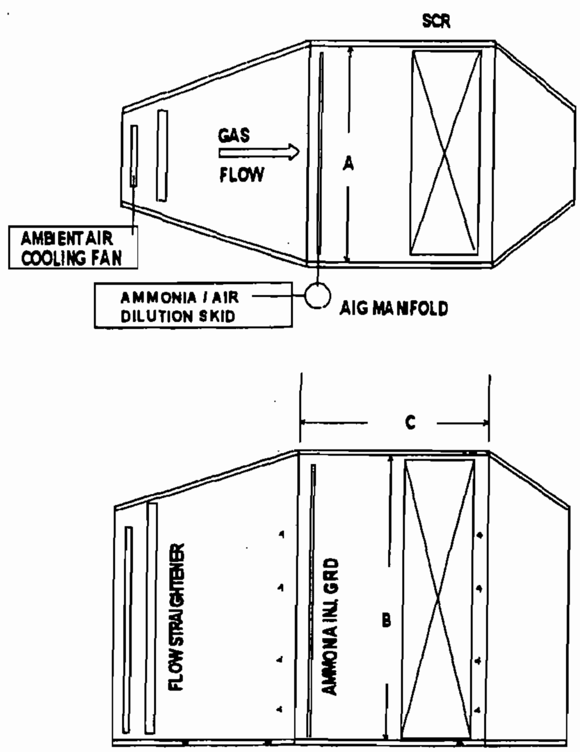
Performance Data

TURBINE			GE 7FA	GE 7EA	GE LM6000
ASSUMED AMBIENT			95	95	95
GIVEN TURBINE EXHAUST TEMPERATURE, F			1,116	998	842
GIVEN TURBINE EXHAUST FLOW, lb/hr			3,427,200	2,314,800	1,008,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL.		N2	74.06	73.24	73.24
		O2	12.50	13.42	13.42
		CO2	3.90	3.80	3.80
		H2O	8.65	8.65	8.65
		Ar	0.89	0.89	0.89
AMBIENT COOLING AIR FLOW, lb/hr			368,745	0	0
TOTAL FLOW – TURBINE EXHAUST + AMBIENT - lb/hr			3,795,945	2,314,800	1,008,000
AMBIENT + EXHAUST GAS ANALYSIS, % VOL.		N2	74.75	73.24	73.24
		O2	13.10	13.42	13.42
		CO2	3.53	3.80	3.80
		H2O	7.82	8.65	8.65
		Ar	0.80	0.89	0.89
CALCULATED AIR + GAS MOL. WT.			28.42	28.40	28.40
GIVEN: TURBINE NOx, ppmvd @ 15% O_2			9.0	9.0	22.0
CALC.: TURBINE NOx, lb/hr			55.9	32.4	34.5
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE			8.7	9.0	22.0
GAS TEMP. @ SCR CATALYST, F			1,025	998	842
DESIGN REQ.	SCR CATALYST	NOx OUT, ppmvd @ 15% O2	2.5	2.5	2.5
		NH3 SLIP, ppmvd @ 15% O2	5	5	5
		SCR PRESSURE DROP, 5"WG – Nom..			
GUARANTEED PERFORMANCE DATA					
	SCR CATALYST	NOx CONVERSION, % - Min.	72.2%	72.2%	88.6%
		NOx OUT, lb/hr - Max.	15.5	9.0	3.9
		NOx OUT, ppmvd @ 15% O2 - Max.	2.4	2.5	2.5
		EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	96	55	51
		NH3 SLIP, ppmvd @ 15% O2 - Max.	5	5	5
		SCR PRESSURE DROP, "WG - Max.	4.5	4.0	4.5
REACTOR INSIDE LINER AREA - A x B, sq ft			**2100**	**1350**	**640**
SCR SYSTEM			**$4,015,000**	**$2,711,000**	**$1,558,000**
REPLACEMENT SCR CATALYST MODULES			**$2,496,000**	**$2,057,000**	**$1,111,000**

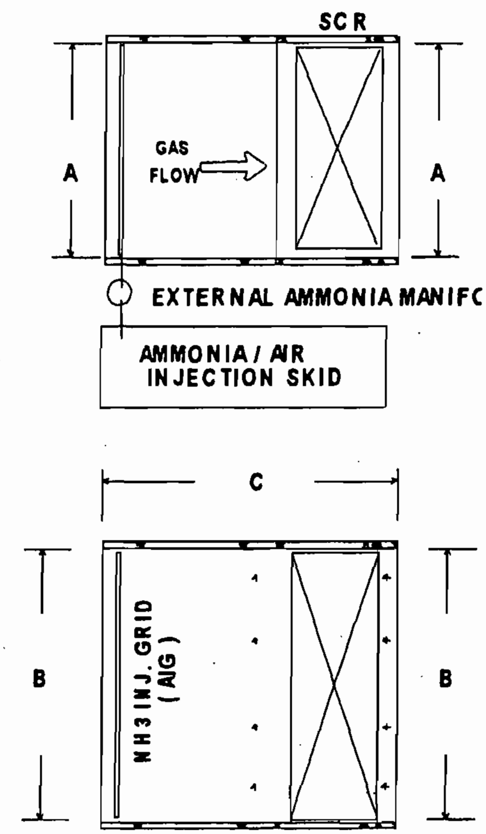
ENGELHARD

Black & Veatch 063045
Simple Cycle Turbines
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99465
June 15, 1999

Dimensions / Sketch: **GE 7FA**
Required Cross Sectional Area
Inside Liner Width x Inside Liner Height
(A x B) sq. ft.
Reactor Depth **(C) 12'-0"**



Dimensions / Sketch:
Required Cross Sectional Area
Inside Liner Width x Inside Liner Height
(A x B) sq. ft.
Reactor Depth **(C) 12'-0"**



ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	June 15, 1999	NO. PAGES	2	(INCLUDING COVER)
TO:	BLACK & VEATCH ATTN: Don Wolf 2401/2845	FAX 913-458-2934		
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841		

High Temp SCR Experience attached.

Engelhard SCR System Experience List

Application	Catalyst	Flow (lb/sec)	Fuel	Start-Up
(1) BBC (50 MW)	VNX	650	NG	11/90
(1) Kawasaki 1 MW	ZNX	23	NG	2/91
(1) Allison 3.5 MW	VNX	38	NG	9/91
(1) Rolls Royce 25 MW	VNX	259	NG	8/92
(2) Westinghouse 251	VNX	422	NG	10/92
(1) GE Frame 7	VNX	669	NG	1Q/93
(1) LM-2500	VNX	157	NG	5/93
(2) LM-6000	VNX	283	NG	4Q/93
(1) LM 5000	VNX	248	NG	1993
(1) LM 5000	VNX	342	NG	1994
(1) GE Frame 6	ZNX	305	NG	1/95
(1) Solar T4500	ZNX	41	NG	1/95
(2) GE Frame 5	ZNX	212	NG	1/95
(1) GE Frame 7	VNX	638	NG	2Q/95
(1) GE Frame 6	VNX	330	NG	1996
(3) ABB GT11N	ZNX	728	#2 Oil	6/96
(1) 2000 Hp	VNX	97	NG	1985
(2) 4000 Hp	VNX	23	NG/DF	1986
(3) 1500 Hp	ZNX	9	DF	5/91
(1) 800 Hp	VNX	8	NG	1993
(1) Refinery Heater	VNX	84	NG	10/90
(1) Refinery Heater	VNX/ZNX	46	NG	10/90
(1) Boiler 1 MW	VNX	26	NG	10/90
(1) Annealing Furnace	VNX	29	NG	1991
(5) Refinery Heater	VNX	16-31	NG	3/91
(1) Refinery Heater	VNX	39	NG	6/91
(1) Refinery Heater	VNX	120.6	#6/NG	1/94
(1) Refinery Heater	VNX	137.8	#6/NG	5/94
(1) Refinery Heater	VNX	110.6	#6/NG	5/94
(1) Utility Boiler (250 MW)	PNX	404	Coal	9/96
(1) Process Off-Gas	ZNX	4	CP	8/90
(1) Nitric Acid Plant	VNX	99	NG	3/91
(1) Process Off-Gas	ZNX	4	CP	1/94
(1) Utility Boiler - LD	VNX		Coal	1985
(8) Gas Turbines	VNX/ZNX		NG	1987
(2) Utility Boiler - LD	VNX/ZNX		Coal	1987
(1) Utility Boiler - HDW	VNX/ZNX		Coal	1989
(1) Utility Boiler - HDD	VNX/ZNX		Coal	1989
(1) Utility Boiler - LD	VNX		Coal	1991
(1) Utility Boiler - HD	VNX		#6 Oil	1991
(2) Turbines	VNX/ZNX		#2 Oil	1994
(1) Utility Air Preheater	PNX		NG/#2 Oil	1994/95
(1) Utility Boiler - HDW	PNX		Coal/NG	2Q/95
(1) Utility Boiler - HDD	PNX		Coal	3Q/95
(1) Utility Boiler - HDD	PNX		Coal	4Q/95

ATTACHMENT E

Table 1

NO_x Control Alternative Capital Cost (Revised)

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts and Ammonia Injection	1,106,000	NA	Scaled from previous projects.
Ductwork and Catalyst Reactor	710,000	NA	Based on conceptual ductwork arrangement
Control/Instrumentation	100,000	NA	Estimated; includes controls and monitoring equipment.
Ammonia Storage	167,000	NA	Scaled from previous projects
Balance of Plant	833,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering, 6 % Retrofit Factor.
Total Direct Capital Cost	2,916,000	Base	
Indirect Capital Costs			
Contingency	729,000	NA	25% of Direct Capital Cost
Engineering and Supervision	208,000	NA	10% of Purchased Equipment Cost
Construction & Field Expense	104,000	NA	5% of Purchased Equipment Cost
Construction Fee	208,000	NA	10% of Purchased Equipment Cost
Start-up Assistance	42,000	NA	2% of Purchased Equipment Cost
Performance Test	35,000	NA	Estimated Cost
Total Indirect Capital Costs	1,326,000	Base	
Total Installed Cost	**4,242,000**	Base	

Table 2

NO_x Control Alternative Annual Cost (Revised)

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			
Catalyst Replacement	121,000	NA	Catalyst life of 3 yr. of equivalent operating hours (5.3 equivalent years)
Operation and Maintenance	16,000	NA	
Reagent Feed	18,000	NA	Assumes 1.4 stoichiometric ratio
Power Consumption	5,000	NA	
Lost Power Generation	150,000	NA	Back pressure on combustion turbine
Annual Distribution Check	15,000	NA	Required for SCR
Total Direct Annual Cost	325,000	NA	
Indirect Annual Costs			
Overhead	7,000	NA	60% of O&M Labor
Administrative Charges	85,000	NA	2% of Total Installed Cost
Property Taxes	42,000	NA	1% of Total Installed Cost
Insurance	42,000	NA	1% of Total Installed Cost
Capital Recovery	355,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	531,000	NA	
Total Annual Cost	**856,000**	NA	
Annual Emissions, tpy	18	90	Emissions from BACT for 5,000 hrs of natural gas firing
Emissions Reduction, tpy	72	NA	Emissions calculated from BACT
Total Cost Effectiveness, $/ton	**11,889**	NA	Total Annual Cost/Emissions Reduction

ATTACHMENT F

Table 3

NO_x Control Alternative Cost

With and Without Contingency

	SCR W/ Contingency	SCR W/out Contingency
Direct Capital Cost		
Catalysts and Ammonia Injection	1,106,000	1,106,000
Ductwork and Catalyst Reactor	710,000	710,000
Control/Instrumentation	100,000	100,000
Ammonia Storage	167,000	167,000
Balance of Plant	833,000	833,000
Total Direct Capital Cost	2,916,000	2,916,000
Indirect Capital Costs		
Contingency	729,000	0
Engineering and Supervision	208,000	208,000
Construction & Field Expense	104,000	104,000
Construction Fee	208,000	208,000
Start-up Assistance	42,000	42,000
Performance Test	35,000	35,000
Total Indirect Capital Costs	1,326,000	597,000
Total Capital Cost	4,242,000	3,513,000
Direct Annual Cost		
Total Direct Annual Cost	325,000	325,000
Indirect Annual Costs		
Overhead	7,000	7,000
Administrative Charges	85,000	70,000
Property Taxes	42,000	35,000
Insurance	42,000	35,000
Capital Recovery	355,000	294,000
Total Indirect Annual Costs	531,000	441,000
Total Annual Cost	**856,000**	**766,000**
Annual Emissions, tpy	18	18
Emissions Reduction, tpy	72	72
Total Cost Effectiveness, $/ton	**11,889**	**10,639**

ATTACHMENT G

BLACK & VEATCH

TELEPHONE MEMORANDUM

B&V Project 63812.0030
7/21/99
11:30 am

Puerto Rico-Simple Cycle Firing No. 2 Fuel Oil
NOx Emission Problems

From:	Mr. Harish Patel
Company:	EPA, Region 2, New York
Phone No.:	(212) 637-4046
Recorded by:	Greg Holscher

The following is a telephone conversation regarding the Cambalache Plant in Puerto Rico. The plant has a simple cycle combustor capable of firing No. 2 fuel oil. The main concern was whether the facility was meeting their permit requirements for NOx output.

Mr. Patel informed me of the following:

1) The Puerto Rico plant was permitted for NOx at 10 ppm and ammonia slip at 10 ppm.
2) They are using water injection followed by an SCR.
3) They are having problems meeting their permit with the SCR.
4) Using a simple cycle turbine, which has a high temperature outlet. They are trying to use a zeolite catalyst for the SCR. The zeolite catalyst does not seem to be working in the SCR like it did in the laboratory.
5) To keep the NOx level low, they are increasing the amount of ammonia injected into the system (decrease NOx results in increasing ammonia slip).
6) The ammonia delivery system is finite, meaning they can only inject so much ammonia into their system.
7) After a few weeks/months the NOx level is slightly increasing. The level of NOx is about 20 to 25 ppm.
8) The ammonia slip is also increasing to about 30 to 40 ppm.
9) When the water injection-SCR system first went into operation, the NOx levels were at about 10 ppm, but are estimated to steadily increase to 42 ppm (42 ppm is the limit using only water injection).
10) Another contact is in Puerto Rico: Mr. Francisco Claudio at (787) 729-6951 Ext. 258

ATTACHMENT H

Kissimmee Utility Authority (KUA)
Cane Island Units 1 & 2
Emission Cap Calculations

Current NOx Permitted Levels (Title V Operating Permit: 0970043-002-AV)

Unit 1 NOx PTE based on:	116.9 tpy
1000 h/yr oil firing	
7760 h/yr gas firing @ 15 ppm NOx	
Unit 2 NOx PTE based on:	290.6 tpy
1000 h/yr oil firing	
7760 h/yr gas firing @ 15 ppm NOx	
Permit Total	**407.5 tpy**

Proposed NOx Cap for Units 1 & 2 (Meeting of 10/20/99)

Unit 1 NOx emissions based on:	86.5 tpy
1000 h/yr oil firing	
5000 h/yr gas firing @ 15 ppm NOx	
Unit 2 NOx emissions based on:	290.6 tpy
1000 h/yr oil firing	
7760 h/yr gas firing @ 15 ppm NOx	
Cap Total	**377.1 tpy**
Resulting Unit 1 & 2 NOx Cap Emission Reduction	30.4 tpy

Unit NOx Emission Information

Unit 1		
	22 lb/h	NOx gas emission rate - 15 ppm@15%O2
	36 lb/h	NOx gas emission rate - 25 ppm@15%O2
	63 lb/h	NOx oil emission rate - 42 ppm@15%O2
Unit 2		
	53 lb/h	NOx gas emission rate - 15 ppm@15%O2
	170 lb/h	NOx oil emission rate - 42 ppm@15%O2

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 24, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information
DEP File No. 0970043-007-AC (PSD-FL-182A)
Modification of NO_X Emission Limitation for Cane Island Power Park Unit 1

Dear Mr. Sharma:

On September 1, 1999 the Department received your application and complete fee for a modification to the air construction permit for Cane Island Unit 1 to change the NO_X limit from 15 ppmvd (at 15% O_2) to 25 ppmvd (at 15% O_2). The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. What are the lowest levels of NO_X that can possibly be consistently achieved with water injection with the LM6000-PA engine, based on the experience of KUA and the engine manufacturer? It appears that tested emissions have averaged about 21 ppm. Are lower emissions are achievable with higher water injection rates?

2. Please evaluate the applicability of spray intercooling to reducing NO_X emissions from this engine.

3. The analysis provided proposed reducing allowable hours of operation firing gas from the current 8760 hours per year to 5000 hours per year. The application information for potential NO_X emissions shows that KUA proposes no reduction in hours of operation for fuel oil firing, allowing for a total of 6000 hours of operation per year (5000 hours for gas firing plus 1000 hours for oil firing). Based on information provided in annual operation reports, Unit 1 has operated 1096 hours in 1996 and 774 hours in 1997, for an average of 935 hours (firing primarily gas). Comparing past actual operation with proposed future operation shows that NO_X emissions will increase by approximately 105 tons per year. Please address this issue.

4. The application proposes no reduction in hours for oil firing even though annual operation reports show that the greatest amount of oil firing was in 1998 with approximately 13 full load hours on oil. It appears that KUA could propose a dramatic reduction in allowable hours for oil firing without compromising the ability to operate the unit. Please comment and provide historical data showing the actual hours of operation firing gas and oil as well as the fuel consumption by fuel type for calendar years 1998 through 1994. We wish to confirm the information available in our records from annual operation reports.

5. Overall, the control cost effectiveness seems high. The analysis does not appear to have been based upon a vendor's quote for a hot SCR system for this installation; an actual quote should be obtained for this analysis. Below are specific points which appear questionable:

A. The contingency of 25% (particularly on top of a 6% retrofit factor) seems very high given that this is commercially available technology.

B. The indirect capital costs were generally calculated as a percentage of the total direct capital cost, although more typically the direct installation costs (in the analysis shown as "balance of plant") are not used to estimate the indirect capital costs.

C. The rate for administrative charges, taxes and insurance at 5.75% is higher than a more typical 4% rate.

D. The nominal interest rate used for the capital recovery factor was 10% (the "real interest rate" shown of 5.5% plus apparently an anticipated annual rate of inflation of 4.5%) although 7% is more typical.

E. The charge for lost power generation from back pressure seems excessive, as does the stated increase in back pressure of 6 inches of water.

F. Catalyst life seems low at 3 years, particularly for a unit that fires primarily gas. The Department is aware of at least one vendor that will guarantee a catalyst life of 3 years inclusive of 1000 hours of annual oil firing, yet no NO_X reductions due to oil firing were included in the analysis.

G. The analysis did not consider the control effectiveness for the allowable use of fuel oil, and did not consider any reduction in annual Title V fees associated with the overall decrease in NO_X emissions from both gas and oil firing.

H. There is no description of what constitutes the "annual distribution check", or justification for this cost.

I. The economic analysis was based on only 5000 hours of operation on gas, although with installation of SCR there would be no reason to limit operation to less than 8760 hours per year.

J. The "starting point" for determining the NO_X reductions appears to presume the continuance of water injection. In the event that an SCR is installed, water injection (for gas as well as oil firing) should be able to be eliminated (or at least reduced). A higher "starting point" should therefore be assumed.

Accounting for these comments would serve to improve the cost effectiveness of SCR. Please provide the basis for costs used in the analysis where they differ from the recommendations in the above comments.

6. Please indicate whether any other (additional) means are available to obtain real offsetting reductions in NO_X emissions from the facility as a whole.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call Mike Halpin at 850/921-9530.

Sincerely,

9/24

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

AAL/jk

cc: Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP CD
D. D. Schultz, Black & Veatch

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114 USA

Tel: (913) 458-2000

Black & Veatch Corporation

Kissimmee Utility Authority
Cane Island – Unit 1 Permit Amendment Request

B&V Project 24489
B&V File 32.0000
August 31, 1999

VIA FEDEX

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
SEP 01 1999
BUREAU OF AIR REGULATION

Subject: Cane Island – Unit 1 Permit Amendment Request

0970043-007-AC

Attention: Al Linero
Administrator, New Source Review Section

Gentlemen:

On behalf of Kissimmee Utility Authority (KUA, the applicant), Black & Veatch is herewith requesting an amendment to Construction Permit No. AC49-205703 (PSD-FL-182) and the Initial Title V Air Operating Permit, Permit No. 0970043-002-AV, to modify Unit 1's 15 ppmvd NOx emission limit during natural gas firing at the Cane Island Power Park. The requested amendment is a direct result of General Electric's (GE) inability to develop a successful dry low emissions (DLE) system for the LM6000 combustion turbine. Specifically, KUA is requesting that Unit 1 be allowed to operate at its currently permitted 25 ppmvd NOx emission rate based on limited annual operation and a revised BACT analysis.

Permitting Background

The air construction application for the Cane Island Power Park was initially filed in 1992. Unit 1 was permitted as a GE LM6000-PA combustion turbine operating in simple cycle mode. The unit is capable of, and permitted to, operate on either natural gas or low sulfur distillate oil.

During the permit issuance process, an initial draft permit, dated October 20, 1992, was issued for public review by the FDEP. In the initial draft, the FDEP accepted the conclusions presented in the air construction application's Best Available Control Technology (BACT) analysis based on the high cost per ton of controlling NOx on the proposed LM6000 combustion turbine ($13,700 for natural gas firing and $9,200 for fuel oil firing). The FDEP further stated that the use of selective catalytic reduction (SCR) technology for NOx control on the LM6000 was not justifiable as BACT. However, despite the facts presented, the FDEP did not permit the LM6000 combustion turbine at a NOx emission level of 25 ppmvd. Instead, the FDEP required that the Unit 1 NOx emissions be lowered from 25 to 15 ppmvd by December 31, 1996 in anticipation of GE's proposed combustion turbine technology improvements for natural gas firing. The FDEP BACT determination is included as Attachment A of this letter. Based upon comments from KUA, Black & Veatch, and GE in 1992 indicating that the development of the DLE system for the LM6000 had not yet begun, the FDEP revised the 15 ppmvd compliance date to December 31, 1997 in the final draft permit issued on November 18, 1992. The final permit issued on April 9, 1993 slightly revised the compliance date to January 1, 1998, allowing the applicant to update the expected compliance dates annually. In addition, the FDEP added language that SCR may be required since its application is technically feasible.

In accordance with permit condition No. 15 of the final permit, KUA submitted a letter to the FDEP on October 24, 1996, providing the revised expected compliance date for Unit 1 (January 1, 1999). The revised compliance date was based upon an aggressive development schedule proposed by GE for their aeroderivative line.

In early 1997, the FDEP requested that the tentative compliance date become a firm date in the permit. As discussed in the following section, due to technological difficulties, the DLE combustor for the aeroderivative line has not proceeded in accordance with the previously anticipated schedule. Because of GE's schedule delay, FDEP amended the compliance date for Unit 1. An amendment to permit (AC0970043-003) was issued on May 19, 1997 extending the reduced NOx emission limit of 15 ppmvd until January 1, 1999. An additional extension was granted on December 15, 1998 via amendment AC0970043-005 further extending this date until January 1, 2000. Specific details regarding GE's DLE development are discussed below.

History of Dry Low Emissions Development

GE launched the development of the DLE program for the aeroderivative combustion turbine line in 1990. Included in the development program was the LM6000 combustion turbine. At the time of installation at Cane Island, one model of LM600 was commercially available. This was the PA model, which utilizes water/steam for NOx control. In late 1994, the PB model became commercially available. This PB model utilized the original LM6000 design but incorporated a DLE combustor for natural gas firing exclusively. Both of the original LM6000 models are no longer in production. These have been replaced with a newer design of aeroderivative machine, which has modifications to the booster vanes and LPT components to improve efficiency, promote stability through larger load ranges, and reduce exhaust noise. The PC model uses water/steam to control NOx emissions and is capable of firing natural gas or fuel oil. The PD model, the DLE combustor version of the PC, became commercially available in late 1997.

The LM6000-PA utilizing water injection for the NOx control is capable of achieving 25 ppmvd NOx when firing natural gas and 42 ppmvd when firing fuel oil. Because this model has been discontinued, there are no DLE development plans for these units. Thus, the only models available with DLE technology available are the old PB units and the newer the PD units. Currently, the PD is capable of meeting 25/65 ppmvd NOx on gas/oil. Past development plans indicated that the dual fuel units would meet a 25/42 ppmvd NOx emission rate, the gas only fired units would meet a 15 ppmvd NOx emission rate, and the technical feasibility of a dual fuel 15/42 ppmvd machine would subsequently be assessed. It now appears that a dual fuel, 15/42 DLE machine will not be available (refer to GE's letter to KUA included as Attachment B).

There are several factors contributing to the DLE development lag between the conventional frame machines and the single fuel aeroderivatives. Specifically, the combustor inlet temperatures are generally higher for aeroderivative machines due to higher compression ratios. This leads to more challenging design problems for combustor liner cooling and flashback avoidance for aeroderivatives. Combustor length and volume are also much higher for frame machines, providing more area for mixing and combustion processes. In addition, the introduction of dual fuel into the aeroderivative presents additional development difficulties. Incorporation of liquid fuel DLE into a gas fuel system makes both the gas and liquid system design more challenging because the liquid fuel is more difficult to premix than natural gas, flashback is more of a problem with liquid fuel, and more distribution apparati/equipment need to fit into the same available space.

While GE has pursued an aggressive schedule for DLE development, difficulties associated with the unique constraints of dual fuel firing in aeroderivative machines have all but stalled any development of a 15/42 DLE machine fix for Unit 1. As such, the applicant is requesting to operate at its currently permitted 25 ppmvd NOx emission rate for natural gas firing, based on a revised BACT and limited annual operation as described below. This approach is the result of the positive and encouraging dialogue that exists between KUA and FDEP, as evident from your e-mail to KUA, included as Attachment C.

Technical Justification for Requested Modification

A revised BACT analysis (included as Attachment D) was performed to assess the economic, environmental, and other factors associated with controlling Unit 1's NOx emissions. Specifically, KUA proposes to operate Unit 1 at the current NOx emission level (25 ppmvd), but decrease the unit's potential operation to 5,000 hours per year. The proposed operation of Unit 1 would decrease the potential annual ton per year emissions below the current permitted level as illustrated below.

Permitted Emission Levels

(22 lb/hr (15 ppmvd) * 8,760 hr/yr) / (2,000 lb/ton) = 96.4 tpy

Proposed Emission Levels

(36 lb/hr (25 ppmvd) * 5,000 hr/yr) / (2,000 lb/ton) = 90.0 tpy

Additional Emissions Reduction

(96.4 tpy (Permitted Emission Level) – 90.0 tpy (Proposed Emission Level)) = 6.4 tpy

As the attached BACT indicates, the economic cost per ton of removed NOx (from 25 ppmvd to 5 ppmvd) for the addition of a SCR for a LM6000 combustion turbine operating to a reduced level of 5,000 hours per year is $15,472. Please note, if this source proposed its operation at 8,760 hours per year the economic cost per ton of removed NOx would decrease to $10,686, which is still considered excessive. To further assist the FDEP in issuing the requested changes to the permit Black & Veatch, is providing revised permit application forms included as Attachment E.

Summary
In summary, GE has not been able to develop the technology for a dual fuel LM6000-PA unit to meet a 15 ppmvd natural gas NOx emission rate, and cannot guarantee when, if ever, such technology may be available. Thus, KUA is requesting an amendment to Construction Permit No. AC49-205703 (PSD-FL-182) and the Initial Title V Air Operating Permit, Permit No. 0970043-002-AV, to modify Unit 1's NOx emission limit during natural gas firing from 15 to 25 ppmvd, based on the attached revised BACT analysis and an operating limit of 5,000 hours per year. As a result of the requested permit amendment, annual potential emissions from Unit 1 will be less than those currently allowed.

If you have any questions regarding this submittal, please do not hesitate to call me at 913-458-7928.

Very truly yours,

BLACK & VEATCH

Timothy M. Hillman
Air Permit Coordinator

kjl
Enclosure[s]

cc: Ben Sharma (KUA)
Jeff Ling (KUA)
Tasha Buford

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 2, 1999

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

Re: KUA Cane Island Unit 1 Permit Amendment Request

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above-mentioned project. It essentially consists of a request to modify the permitted NOx limit from 15 ppm (which begins on 1/1/00) to 25 ppm (the current limit). The applicant indicates that they are willing to accept a reduction in hours of operation in order to ensure that the annual NOx tonnage (potential to emit) does not increase.

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. If you have any questions, please contact Mike Halpin at (850) 921-9530.

Sincerely,

MPHalpin for AAL

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

AAL/mph/kt

Enclosures

cc: Mike Halpin, BAR

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 2, 1999

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

Re: KUA Cane Island Unit 1

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above-mentioned project. It essentially consists of a request to modify the permitted NOx limit from 15 ppm (which begins on 1/1/00) to 25 ppm (the current limit). The applicant indicates that they are willing to accept a reduction in hours of operation in order to ensure that the annual NOx tonnage (potential to emit) does not increase.

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. If you have any questions, please contact Mike Halpin at (850) 921-9530.

Sincerely,

MHalpin for AAL

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

AAL/mph/kt

Enclosures

cc: Mike Halpin, BAR

Attachment A

Best Available Control Technology (BACT) Determination
Kissimmee Utility Authority
Osceola County
PSD-FL-182

The applicant proposes to install two combustion turbine generators at their facility near Intercession City, Osceola County. These generator systems will consist of: 1) one nominal 80 megawatt (MW) General Electric PG7111EA combined cycle combustion turbine (CCCT), with exhaust through a heat recovery steam generator (HRSG), which will be used to power a nominal 40 MW steam turbine and 2) a 40 MW General Electric LM6000 simple cycle combustion turbine (SCCT).

The PG7111EA combustion turbine will be capable of operating on a combined and a simple cycle mode. The LM6000 will operate on a simple cycle mode. The applicant has requested to burn natural gas or fuel oil No. 2, with a 0.05 percent sulfur content, on a continuous basis (8,760 hrs/year). The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity factor, ISO conditions, and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Oil		Gas		PSD Significant Emission Rate (TPY)
	PG7111EA	LM6000	PG7111EA	LM6000	
NO_x	744.6	275.9	429.2	157.7	40
SO_2	227.8	87.6	nil	nil	40
PM/PM_{10}	65.7	52.6	30.7	39.4	25/15
CO	284.7	332.9	236.5	175.2	100
VOC	21.9	13.1	8.8	6.1	40
H_2SO_4	25.1	9.6	nil	nil	7
Be	0.0099	0.0035	---	---	0.0004
Hg	0.012	0.005	---	---	0.1
Pb	0.044	0.141	---	---	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

June 2, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) PG7111(EA) Control Technology: Low NO_x Burners GE LM6000 Control Technology: Water Injection

SO_2	0.3% sulfur by weight (but limited to 0.05% sulfur for modeling purposes)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-296, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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:

(a) Any Environmental Protection Agency determination of Best Available Control Technology 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) 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 source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, than 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.

The air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- o Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.

- o Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.

- o Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbines when burning natural gas and fuel oil will not exceed 15 lbs/hr (oil) and 7 lbs/hr (gas) for the PG7111 and 12 lbs/hr (oil) and 9 lbs/hr (gas) for the LM6000. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

Lead, Mercury, Beryllium (Pb, Hg, Be)

The Department agrees with the applicant's rationale that there are no feasible methods to control lead, mercury, and beryllium; except by limiting the inherent quality of the fuel.

Although the emissions of these toxic pollutants could be controlled by particulate control devices, such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of these pollutants.

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed combined cycle turbine with a "quiet combustor" are 10 ppmv for natural gas firing and 20 ppmv for fuel oil firing. However, for a dry low NO_x combustor, the emission limit is 20 ppmvd for both oil and gas. For the simple cycle CT, the CO emissions for firing natural gas and fuel oil are 30 ppmv and 63 ppmv, respectively.

The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, however, additional control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of $4,437 per ton for the LM6000 and $10,560 per ton for the PG7110EA of CO/VOC removed will have an economic impact on this project.

The Department is in agreement with the applicant's proposal of combustor design and good operating practices as BACT for CO and VOCs for this cogeneration project.

ACID GASES

Nitrogen Oxides (NO_x)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using water injection and advanced combustor design to limit emissions to 25 ppmvd (corrected to 15% O_2) when burning natural gas and 42 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

The effect of exhaust gas temperature on NO_x reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NO_x control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

As stated by the applicant, the exhaust temperatures of the proposed simple cycle CTs for this site are between 600°F to 800°F.

At temperatures of 1,000°F and above, the zeolite catalyst (reported to operate within 600°F to 950°F) will be irreparably damaged. In this case, application of an SCR system using a zeolite catalyst on a simple-cycle operation appears to be technically feasible.

However, the applicant has rejected using SCR on the simple cycle CT because of economic and environmental impacts.

Although technically feasible, the applicant has also rejected using SCR on the combined cycle because of economic, energy, and environmental impacts. The applicant has identified the following limitations:

a) Reduced power output.
b) Emissions of unreacted ammonia (slip).
c) Disposal of hazardous waste generated (spend catalyst).
d) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
e) Cost effectiveness for the application of SCR technology to the Kissimmee Utility project was considered to be $9,879 per ton of NO_X removed for the PG7111EA and $13,700 per ton of NO_X removed for the LM6000 when burning natural gas.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NO_X emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater ammonia injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 80 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $2,944,000 for the PG7111EA and $1,589,000 for the LM6000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For the PG7111EA combined cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using low NO_x burner will be 372 tons/year (natural gas) and 700 tons/year (oil firing). Assuming that SCR would reduce the NO_x emissions by 80%, about 74 tons of NO_x (natural gas) and 140 tons of NO_x (oil) would be emitted annually. When this reduction (298 TPY natural gas and 560 TPY oil) is taken into consideration with the total levelized annual operating cost of $2,944,000 (natural gas) and $3,424,000 (oil firing); the cost per ton of controlling NO_x is $9,879 (natural gas) and $6,114 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

For the simple cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using water injection will be 145 tons/year (natural gas) and 250 tons/year (oil firing). Assuming that SCR would reduce the NO_x emissions by 80%, about 29 tons of NO_x (natural gas) and 50 tons of NO_x (oil firing) would be emitted annually. When this reduction (116 TPY natural gas and 200 TPY oil) is taken into consideration with the total levelized annual operating cost of $1,589,000 (natural gas) and $1,840,000 (oil firing); the cost per ton of controlling NO_x is $13,700 (natural gas) and $9,200 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will be available by 1997, the Department has accepted the water injection (LM6000), low NO_x burner design (PG7111EA), and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 1/1/98).

Sulfur Dioxide(SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant has stated that sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions when firing fuel oil will be controlled by using fuel oil with a maximum sulfur content of 0.05 % by weight. This will result in an annual emission rate of 18 tons SO_2 per year and 2 tons H_2SO_4 mist per year (operating at 500 hours per year).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable."(23). EPA reinforced this point when, later on in the preamble, they stated that "FGD... would cost about two to three times as much as the gas turbine."(23). The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the open literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option then leaves the use of low sulfur fuel oil as the next option to be investigated. Kissimmee Utility Authority, as stated above, has proposed the use of No. 2 fuel oil with a 0.05% sulfur by weight as BACT for this project. The Department accepts their proposal as BACT for this project.

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for these turbines [$9,879 (gas) PG7111EA, $6,114 (oil) PG7111EA, $13,700 (gas) LM6000, and $9,200 (oil) LM6000] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water injection and low NO_x burner design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that General Electric is developing programs for the PG7111EA and the LM6000, using either steam/water injection or dry low NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Therefore, the Department has determined that the following BACT will apply by 1/1/98.

a) For the combined cycle unit (PG7111EA), if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 1/1/98, SCR will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.
b) For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved, the permittee must notify the Department of the expected compliance date by 1/1/97.
c) For both turbines (PG7111EA and LM6000), when the manufacturer achieves an even lower NO_x emission level than 15 (gas)/42 (oil) ppmv, this level may become a condition of this permit.

SO_2 Control

BACT for sulfur dioxide is the burning of fuel oil No. 2 with 0.05% sulfur content by weight.

VOC and CO Control

Combustion control will be considered as BACT for CO and VOC when firing natural gas.

Other Emissions Control

The emission limitations for PM and PM_{10}, Be, Pb, and Hg are based on previous BACT determinations for similar facilities.

The emission limits for Kissimmee Utility Authority project are thereby established as follows:

120 MW COMBINED CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil[(a)]	Gas[(b)]	Method of Control
NO_x	42 ppmv	25 ppmv[(c)]	Water Injection/ Quiet Combustor or Dry Low NO_x Combustor
		15 ppmv	Water Injection/Dry Low NO_x Combustor
CO	65 lbs/hr	54 lbs/hr	Combustion
PM & PM10	15 lbs/hr	7 lbs/hr	Combustion
SO_2	52 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	5.7 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	5 lbs/hr	2 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.
(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous burning of No. 2 fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.
(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor

injection technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved, the permitte shall install SCR.

40 MW SIMPLE CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil(a)	Gas(b)	Method of Control
NO_x	42 ppmv	25 ppmv(c) 15 ppmv	Water Injection Dry Low NO_x Combustor
CO	76 lbs/hr	40 lbs/hr	Combustion
PM & PM10	12 lbs/hr	9 lbs/hr	Combustion
SO_2	20 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	2.2 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	3 lbs/hr	1.4 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.

(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous firing of fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.

(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

April 1, 1993
Date

Approved by:

Virginia B. Wetherell
Virginia B. Wetherell, Secretary
Dept. of Environmental Regulation

April 7, 1993
Date

Attachment B

08/26/99 09:44 FAX → B&V 001/002

fax to: Myron Rollins
Tim Hillman
Tosha Buford
Ben 8/26
Copy: Jeff

Best Available Copy

GE Power Systems

Zigmond F. Biernacki
Account Executive

General Electric International, Inc.
Waterford Plaza, Suite 900
7650 W. Courtney Campbell Cswy.
Tampa, FL 33607
Phone: (813) 286-4834 Fax: (813) 286-4808
Email: zig.biernacki@ps.ge.com

Bel

August 24, 1999

Kissimmee Utility Authority
1701 W. Carroll St.
Kissimmee, Florida 33741

Attention: Mr. A. L. (Ben) Sharma
Director of Power Supply

Subject: GE LM6000
DLE Update

GE PROPRIETARY INFORMATION

Dear Ben,

As a follow-up to our discussions last week, I have attached a summary of where the GE Industrial AeroDerivative group is in the development and commercial availability of a dual fuel Dry Low Emission (DLE) system for the LM6000.

Please note that the **Information presented on the Attachment is considered Proprietary to the GE Company and should be treated as such.**

If you have any questions, do not hesitate to contact me.

Best regards,

Zig Biernacki

Z. F. Biernacki

enclosure

Post-it® Fax Note 7671	Date 8-26	# of pages ▶ 2
To Myron Rollins	From Ben Sharma	
Co./Dept. B+V	Co. KUA	
Phone #	Phone #	
Fax #	Fax #	

26 9

GE Industrial AeroDerivative
Gas Turbines

August 24, 1999

LM6000 Dry Low Emissions (DLE)

Status and Commercial Availability Summary Report

The purpose summary report is to provide an update on the technical status and commercial availability of LM6000 dry low emissions products offered by GE Industrial Aeroderivative Gas Turbines.

Natural Gas Fired Technology and Product Offerings

Technology development has been pursued on LM6000 model PB and model PD with the objective of meeting 15 ppm dry.

LM6000PB: Testing was conducted at the Orange Cogeneration Limited Partnership Bartow facility between 1996 and 1998, various design changes including premixer airflow variations, premixer pressure drop adjustments and inlet guide vane schedule adjustment produced improvements from initial levels of 21-22 ppm down to 17-18 ppm at LM6000PB rated power.

LM6000PD: Premixer changes tested at Bartow were evaluated in LM6000PD in December 1998. Reductions of approximately 3-4 ppm were obtained with the premixer adjustments at the LM6000PD rating level. but this reduction was not sufficient for GE to guarantee 15 ppm.

Commercial Product Offering . GE currently offers the LM6000PD at 25 ppm NOx (ref 15%O2). The LM6000 PB is no longer offered.

Dry Liquid Fuel Technology and Product Offerings

LM6000PD: One LM6000 PD with dual fuel dry low emissions has been commissioned and one is currently in the commissioning phase. At LM6000PD rated power, the NOx emissions for the liquid fuel has been measured at 160 ppm NOx.

Long term product objective is to reduce the liquid dry emissions performance to meet 65 ppm. A program is in progress to deliver production hardware the 4th quarter of 2000.

GE Proprietary Information

Attachment C

From: Alvaro Linero TAL 850/921-9532 <LINERO_A@dep.state.fl.us>
To: KUA.Mail5(BSHARMA,JLING)
Date: 11/5/98 8:23AM
Subject: Air Construction Permit - Cane Island Unit 1

Attached is the Public Notice to extend the 15 ppm NOx compliance period by one year. The matter can probably be addressed in the certification of Cane Island Unit 3. I recommend developing some options such as limiting hours of operation if a technological solution is not in site. At the administrative hearing next summer, there will have to be a more concrete solution.

SCA file

I will advise the Title V Section that they can revise their draft permit as soon as we complete the 30 day comment period after you publish the attached notice. Thanks. Al Linero.

CC: Mike Halpin TAL <HALPIN_M@dep.state.fl.us>

Attachment D

BACT Analysis

Project Description

Cane Island Unit 1 began operation in 1994. It consists of an LM6000 simple cycle combustion turbine with dry low NOx combustors designed to achieve 25 ppmvd NOx at 15 percent O_2. The combustion turbine fires natural gas with No. 2 fuel oil backup. The proposed operating scenario for the combustion turbine consists of intermittent (peaking) operation up to 5,000 hours per year. The purpose of this document is to determine Best Available Control Technology Analysis for NOx emissions.

BACT Methodology

BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (March 15, 1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. Technologies required under Lowest Achievable Emission Rate (LAER) determinations must be considered. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

Economic analysis used to determine the capital and annual costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA BACT Guidelines, The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fourth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

Economic Basis

Table 1 lists the economic criteria used in the analysis of BACT alternatives.

Table 1
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	25
Real Interest Rate, percent	5.50
Economic Life years	20
Labor Cost, $/man-hr	26
Aqueous Ammonia Cost, $/ton (1999)	350
Energy Cost, $/kWhr (1999)	0.023
Catalyst Life, years	3

Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. Emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxides control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. Currently, Cane Island Unit 1 is equipped with dry low NOx burners. The manufacturer has indicated that for the LM6000 machine, 25 ppmvd at 15 percent O_2 is the lowest achievable emission rate without the edition of post combustion NOx controls.

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called dry low NO_x burners, because when firing fuel, no water needs to be injected into the combustion chamber to achieve low NO_x emissions.

DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process ensures good mixing of the air and fuel and minimizes the amount of air required, which results in low NO_x emissions.

Another form of in-combustor control is Xonon. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700 °F at full power generation, which significantly reduces NO_x emissions without raising and possibly even lowering emissions of carbon monoxide and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers. To date, commercialization of this technology on utility size has not been developed.

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. However, the exhaust temperature at the exit of a combustion turbine, which ranges from 1,000 to over 1,200 °F for combustion turbines, is too low for any consideration of this technology. Temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time at this temperature range, are required to use this technology.

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in combined cycle combustion turbine projects for the past 5 years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades ammonia slip will increase to approximately 10 ppm, ultimately requiring catalyst replacement.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadia/titania catalysts have been used on the vast majority of SCR system installations (greater than 95 percent).

The flue gas temperature range for optimum SCR operation using a conventional vanadia/titania catalyst is approximately 600 to 750 °F. At temperatures above 800 °F permanent damage to the vanadia/titania catalyst occurs. For Cane Island Unit 1, this temperature window does not exist. Flue gas from a combustion turbine is 840 °F. Accordingly, a vanadia/titania catalyst can not be installed at a simple cycle facility. Therefore, the vanadia/titania based catalyst will not be evaluated further for this unit.

However, another catalyst material has been developed to which has had mixed success in limited application experiences. This catalyst uses zeolites, which can operate effectively at temperatures of up to 1,125 °F, as the principle catalytic material. Zeolites, which are crystalline aluminasilicate compounds, do not contain materials classified as hazardous. Therefore, it is possible that these SCR catalysts can be disposed of by landfilling provided that contamination does not occur during SCR operation. Disposal would be subject to state and local regulations. Since zeolites have the most limited use of SCR catalysts, disposal requirements have not been adequately established. Zeolite based catalyst is significantly more expensive than the vanadia/titania based catalyst. In addition, the durability and effectiveness of zeolites in commercial SCR applications does not have a long history base.

The operation of zeolite catalyst on sulfur bearing fuel fired units, such as oil fired units, also has very limited experience. In addition, the operation of a SCR on units that burn sulfur-bearing fuels will present a negative impact on the environmental performance of combustion turbine units. The environmental impact is due to the reaction of the excess ammonia that passes through the SCR with the sulfur trioxide (SO_3) in the flue gas to form significant quantities of ammonia-sulfur salts, such as ammonium bisulfate. These compounds form when the flue gas cools upon leaving the stack. This fine particulate significantly adds to the emissions of PM_{10} from the unit. This PM_{10} contributes to increased opacity from the unit, increased contribution to regional haze, and additional health risks. Furthermore, the installation of an SCR would need to consider low overall catalyst activity and higher catalyst deactivation rates due to sulfur poisoning of the catalyst. Previous regulating authorities have recognized these negative impacts and provided permit exemptions for operating the SCR during fuel oil firing.

This method of post-combustion control will be considered in this BACT analysis to control NO_x emissions when firing natural gas only.

Technology Summary

The following control technologies will be evaluated in this NO_x BACT analysis and are ranked in order of relative control effectiveness:

- The addition of zeolite catalyst SCR systems to reduce outlet emissions from each combustion turbine to 5.0 during natural gas firing (LAER), respectively.

- In-combustor NO_x control consisting of dry low NO_x combustors to limit outlet emissions during natural gas firing to 25 ppmvd.

Technical Evaluation

Table 2 lists the emissions from Cane Island Unit 1 with and without the addition of SCR.

Table 2
Estimated NO_x Emissions
From Alternate Control Technologies

	Control Technology Alternatives	
	Dry Low NO_x Combustors	SCR System
Natural Gas Firing		
ppmvd (at 15% O_2)	25	5
Tons per year[a] – 5,000 hours operation	90	18

Note:

Annual emissions are based on 5,000 hours of natural gas operation per year at full load rating with an average ambient temperature of 59 °F.

Table 3 shows the capital costs associated with retrofitting a high temperature SCR to Cane Island Unit 1. These costs include the extra ductwork that would be required to add the SCR reactor to the existing facility. The costs also include a retrofit factor to account for the costs associated with installing a new SCR system on an existing unit. Table 4 lists the annual costs associated by high temperature SCR.

Table 3

NO_x Control Alternative Capital Cost

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts and Ammonia Injection	1,106,000	NA	Scaled from previous projects.
Ductwork and Catalyst Reactor	710,000	NA	Based on conceptual ductwork arrangement
Control/Instrumentation	100,000	NA	Estimated; includes controls and monitoring equipment.
Ammonia Storage	167,000	NA	Scaled from previous projects
Balance of Plant	833,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering, 6 % Retrofit Factor.
Total Direct Capital Cost	2,916,000	Base	
Indirect Capital Costs			
Contingency	729,000	NA	25% of Direct Capital Cost
Engineering and Supervision	292,000	NA	10% of Direct Capital Cost
Construction & Field Expense	146,000	NA	5% of Direct Capital Cost
Construction Fee	292,000	NA	10% of Direct Capital Cost,
Start-up Assistance	58,000	NA	2% of Direct Capital Cost
Performance Test	35,000	NA	Estimated Cost
Total Indirect Capital Costs	1,552,000	Base	
Total Installed Cost	**4,468,000**	Base	

Table 4

NO_x Control Alternative Annual Cost

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			
Catalyst Replacement	121,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	16,000	NA	
Reagent Feed	18,000	NA	Assumes 1.4 stoichiometric ratio
Power Consumption	5,000	NA	
Lost Power Generation	150,000	NA	Back pressure on combustion turbine
Annual Distribution Check	15,000	NA	Required for SCR
Total Direct Annual Cost	325,000	NA	
Indirect Annual Costs			
Overhead	7,000	NA	60% of O&M Labor
Administrative Charges	89,000	NA	2% of Total Installed Cost
Property Taxes	123,000	NA	2.75% of Total Installed Cost
Insurance	45,000	NA	1% of Total Installed Cost
Capital Recovery	525,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	789,000	NA	
Total Annual Cost	**1,114,000**	NA	
Annual Emissions, tpy	18	90	Emissions from Table 2 for 5,000 hrs of natural gas firing
Emissions Reduction, tpy	72	NA	Emissions calculated from Table 2
Total Cost Effectiveness, $/ton	**15,472**	NA	Total Annual Cost/Emissions Reduction

Energy Impacts

The use of an SCR system impacts the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the aqueous ammonia reagent for injection. In addition, the ductwork and catalyst will increase the back pressure on each combustion turbine. It is anticipated that the ductwork and SCR system will result in approximately 6 inches water gauge (in. w.g.) back pressure to each type of unit. Increased power consumption and lost power generation are included in the annual cost estimate.

Environmental Impacts

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes. With proper precautions, aqueous ammonia can be stored and used safely.

Some ammonia slip from the combustion turbine stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. At least one air pollution control district in California recently set an ammonia slip emissions limit of 10 ppmvd (uncorrected). Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates associated catalyst replacement. A design value of 10 ppmvd (uncorrected) is appropriate for a clean fuel facility such as this Project. With fresh catalyst ammonia slip emissions will be very low. However, as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and may be classified as hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

When firing fuel oil or any sulfur bearing fuel, the SCR catalyst will oxidize approximately 2 to 3% of the SO_2 in the flue gas to SO_3. This oxidation occurs at all times, even if ammonia is not being injected. The SO_3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. The additional particulate material resulting from sulfuric acid mist will predominately consist of matter less than 10 microns in diameter (PM_{10}).

Conclusions

SCR systems are representative of the LAER level of NO_x emissions reduction. SCR systems have been successfully used on numerous combined cycle combustion turbine applications but have limited experience mixed results on simple cycle combustion turbine applications. The fundamental obstacle to the use of these systems on a simple cycle combustion turbine is the overall economics and the potential primary (SO_2 to SO_3 oxidation) environmental impacts when firing sulfur bearing fuels. NO_x reduction costs for the proposed turbines are $15,472 per ton of removed NO_x. This overall annual cost of the SCR to meet NO_x emission limits of 5.0 ppmvd during natural gas firing is judged to be excessive. Furthermore, SCR use may result in significant PM_{10} emissions caused by the additional SO_2 to SO_3 oxidation and H_2SO_4 emissions. In addition, the potential to poison the catalyst with sulfur bearing compounds during fuel oil firing severally limits the use of an SCR. Therefore, based on energy, environmental and economic impacts, the use of dry low NO_x combustors to meet an emissions level of 25 ppmvd during natural gas firing is recommended as BACT for Cane Island Unit 1.

Attachment E

Kissimmee Utility Authority
Cane Island Power Park

Permit Amendment Application

For

Cane Island Unit 1

August 1999

BLACK & VEATCH

Contents

Appendix

I. Application Information

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Kissimmee Utility Authority	
2. Site Name : Cane Island Power Park	
3. Facility Identification Number : 0970043	[ ] Unknown
4. Facility Location : Kissimmee Utility Authority (KUA) Cane Island Power Park Located 10 km west of Kissimmee, near Intercession City, Osceola County, Florida Street Address or Other Locator : 6075 Old Tampa Hwy City : Intercession City County : Osceola	Zip Code : 33848-9999
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Rec'd: 9/1/99
0970043-007-AC
PSD-FL-182a

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : A. K. Sharma
Title : Director of Power Supply

2. Owner or Authorized Representative or Responsible Official Mailing Address :

Organization/Firm : Kissimmee Utility Authority
Street Address : 1701 West Carroll Street
City : Kissimmee
State : FL Zip Code : 34741-6804

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (407)933-7777 Fax : (407)847-0787

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*

AK Sharma
Signature

8|26|99
Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Unit 1 - 40 MW Simple Cycle Combustion Turbine	NA

Purpose of Application and Category

ategory I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, .A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[X] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :
0970043-002-AV

Reason for revision :

ategory II : All Air Operation Permit Applications Subject to Processing Under Rule 2-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[ ] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :

[X] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s) :
0970043-002-AV

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one :

[ ] Attached - Amount : $0.00 [X] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : Kissimmee Utility Authority, Cane Island Power Park The original construction permit (AC 49-205703) and operating permit (0970043-002-AV) for Unit 1 (LM6000) were based on 7,760 hr/yr of natural gas firing with a NOx emission limit of 25 ppmvd, which would be lowered to 15 ppmvd with the advent of GE's DLE combustor. To date, GE's DLE system for the LM6000 machine to lower the NOx emission rate from 25 to 15 ppmvd during natural gas firing has not materialized. Therefore, this application proposes a modification to the aforementioned permits based on a revised BACTanalysis and a reduction in hours of natural gas operation. Specifically, the requested permit amendments allow Unit 1 operation at 25 ppmvd on natural gas for 5,000 hours per year, in addition to the permitted fuel oil use.
2. Projected or Actual Date of Commencement of Construction :
3. Projected Date of Completion of Construction :

Professional Engineer Certification

1. Professional Engineer Name : D. D. Schultz Registration Number : 30304
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Street Address : 8400 Ward Parkway City : Kansas City State : MO Zip Code : 64114-2031
3. Professional Engineer Telephone Numbers : Telephone : (913)458-2028 Fax : (913)458-2934

4. Professional Engineer Statement :

I, the undersigned, hereby certify, except as particularly noted herein, that :*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

D D Schultz — August 27, 1999

Signature — Date

(seal) DEAN SCHULTZ, CERTIFICATE NO. 3[illegible], STATE OF FLORIDA, REGISTERED ENGINEER

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact : Name : A. K. Sharma Title : Director of Power Supply
2. Application Contact Mailing Address : Organization/Firm : Kissimmee Utility Authority Street Address : 1701 West Carrol Street City : Kissimmee State : FL Zip Code : 34741-6804
3. Application Contact Telephone Numbers : Telephone : (407)933-7777 Fax : (407)847-0787

Application Comment

II. Facility Information

General Facility Information

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type 539

1. Facility UTM Coordinates : Zone : 17 East (km) : 447.72 North (km) : 3127.68			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 28 16 32 Longitude (DD/MM/SS) : 81 31 59			
3. Governmental Facility Code : 0	4. Facility Status Code : A	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) :
7. Facility Comment :			

Facility Contact

1. Name and Title of Facility Contact : Jeff Ling Plant Manager
2. Facility Contact Mailing Address : Organization/Firm : KUA Cane Island Power Plant Street Address : 6075 Old Tampa Hwy City : Intercession City State : FL Zip Code : 33848-9999
3. Facility Contact Telephone Numbers : Telephone : (407)846-7070 Fax : (407)846-6485

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	Y
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment : Facility units currently exempt under NESHAPs. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used. Therefore, the cooling tower is not a major source of HAPs.	

Facility Regulations

B. FACILITY REGULATIONS

Rule Applicability Analysis

N/A - Facility is a Title V source

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 73.52 - EPA Recordation

Section 73.53 - Notification

Subpart E - Auctions, Direct Sales, and Independent Power Producers Written

Section 73.70 - Auctions

Section 73.71 - Bidding

Section 73.72 - Direct Sales

Section 73.73 - Delegation of Auctions and Sales and Termination of Auctions

Section 73.74 - Independent Power Producers Written Guarantee

Section 73.75 - Application for an IPP Written Guarantee

Section 73.76 - Approval and Exercise of the IPP Written Guarantee

Section 73.77 - Relationship of Independent Power Producers Written Guarantee

Subpart F - Energy Conservation and Renewable Energy Reserve

Section 73.80 - Operation of Allowance Reserve Program for Conservation and

Section 73.81 - Qualified Conservation Measures and Renewable Energy

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 73.82 - Application for Allowances from Reserve Program

Section 73.83 - Secretary of Energy's Action on Net Income Neutrality

Section 73.84 - Administrator's Action on Applications

Section 73.85 - Administrator Review of the Reserve Program

Section 73.86 - State Regulatory Autonomy, Appendix A to Subpart F--List of

Part 75 - Emission Monitoring

Subpart A - General

Section 75.1 - Purpose and Scope

Section 75.2 - Applicability

Section 75.3 - General Acid Rain Program Provisions

Section 75.4 - Compliance Dates

Section 75.5 - Prohibitions

Section 75.6 - Incorporation by Reference

Section 76.7 - EPA Study

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 76.8 - [Reserved]

Subpart B - Monitoring Provisions

Section 75.10 - General Operating Requirements

Section 75.11 - Specific Provisions for Monitoring SO2 Emissions (SO2 and flow

Section 75.12 - Specific Provisions for Monitoring NOx Emissions (NOx and

Section 75.13 - Specific Provisions for Monitoring CO2 Emissions

Section 75.14 - Specific Provisions for Monitoring Opacity

Section 75.15 - Specific Provisions for Monitoring SO2 Emissions Removal by

Section 75.16 - Specific Provisions for Monitoring Emissions from Common, By-

Section 75.17 - Specific Provisions for Monitoring Emissions from Common, By-

Section 75.18 - Specific Provisions for Monitoring Emissions from Common and

Subpart C - Operation and Maintenance Requirements

Section 75.20 - Certification and Recertification Procedures

Section 75.21 - Quality Assurance and Quality Control Requirements

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.22 - Reference Test Methods

Section 75.23 - Alternatives to ASTM Methods

Section 75.24 - Out-of-Control Periods

Subpart D - Missing Data Substitution Procedures

Section 75.30 - General Procedures

Section 75.31 - Initial Missing Data Procedures

Section 75.32 - Determinations of Monitor Data Availability for Standard Missing

Section 75.33 - Standard Missing Data Procedures

Section 75.34 - Units with Add-On Emission Controls

Subpart E - Alternative Monitoring Systems

Section 75.40 - General Demonstration Requirements

Section 75.41 - Precision Criteria

Section 75.42 - Reliability Criteria

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.43 - Accessibility Criteria

Section 75.44 - Timelines Criteria

Section 75.45 - Daily Quality Assurance Criteria

Section 75.46 - Missing Data Substitution Criteria

Section 75.47 - Criteria for a Class of Affected Units

Section 75.48 - Petition for an Alternative Monitoring System

Subpart F - Recordkeeping Requirements

Section 75.50 - General Recordkeeping Provisions

Section 75.51 - General Recordkeeping Provisions for Specific Situations

Section 75.52 - Certification, Quality Assurance and Quality Control Record

Section 75.53 - Monitoring Plan

Subpart G - Reporting Requirements

Section 75.60 - General Provisions

Section 75.61 - Notification of Certification and Recertification Test Dates

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.62 - Monitoring Plan

Section 75.63 - Certification or Recertification Applications

Section 75.64 - Quarterly Reports

Section 75.65 - Opacity Reports

Section 75.66 - Petitions to the Administrator

Section 75.67 - Retired Units Petitions

Part 76 - EPA Regulations on Acid Rain Nitrogen Oxides

Section 76.1 - Applicability

Section 76.2 - Definitions

Section 76.3 - General Acid Rain Program Provisions

Section 76.4 - Incorporation by Reference

Section 76.5 - NOx Emission Limitations for Group 1 Boilers

Section 76.6 - NOx Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 - Revised NOx Emission Limitations for Group 1, Phase II Boilers

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 76.8 - Early Election for Group 1, Phase II Boilers

Section 76.9 - Permit Application and Compliance Plans

Section 76.10 - Alternative Emission Limitations

Section 76.11 - Emissions Averaging

Section 76.12 - Phase I NOx Compliance Extensions

Section 76.13 - Compliance and Excess Emissions

Section 76.14 - Monitoring, Recordkeeping, and Reporting

Section 76.15 - Test Methods and Procedures

Section 76.16 - [Reserved]

Part 77 - Excess Emissions

State Applicable Requirements

Chapter 62-4, F.A.C.; PERMITS

62-4.055 - Permit Processing

Chapter 62-210, F.A.C.; STATIONARY SOURCES - GENERAL REQUIREMENTS

B. FACILITY REGULATIONS

List of Applicable Regulations

62-210.550 - Stack Height Policy

62-210.700 - Excess Emissions

Chapter 62-212, F.A.C.; STATIONARY SOURCES - PRECONSTRUCTION REVIEW

62-212.300 - General Preconstruction Review Requirements

62-212.400 - Prevention of Significant Deterioration

62-212.410 - Best Available Control Technology

Chapter 62-213, F.A.C.; OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION

62-213.413 - Fast-Track Revisions of Acid Rain Parts

Chapter 62-214, F.A.C.; REQUIREMENTS FOR SOURCES SUBJECT TO THE FEDERAL ACID RAIN PR

62-214.300 - Applicability

62-214.320 - Applications

62-214.330 - Acid Rain Compliance Plan and Compliance Options

62-214.350 - Certification

62-214.370 - Revisions and Administrative Corrections

B. FACILITY REGULATIONS

List of Applicable Regulations

62-214.420 - Acid Rain Part Content

62-214.430 - Implementation and Termination of Compliance Options

Chapter 62-272, F.A.C.; AMBIENT AIR QUALITY STANDARDS

62-272.500 - Maximum Allowable Increases

Chapter 62-273, F.A.C.; AIR POLLUTION EPISODES

62-273.300 - Air Pollution Episodes

62-273.400 - Air Alert

62-273.500 - Air Warning

62-273.600 - Air Emergency

Chapter 62-296, F.A.C.; STATIONARY SOURCES - EMISSION STANDARDS

62-296.405 - Fossil Fuel Steam Generators

Chapter 62-297, F.A.C.; STATIONARY SOURCES - EMISSIONS MONITORING

62-297.401 - Compliance Test Methods

62-297.440 - Supplementary Test Procedures

B. FACILITY REGULATIONS

List of Applicable Regulations

62-297.520 - EPA Performance Specifications

62-297.620 - Exceptions and Approval of Alternate Procedures and Requirements

62-297.310, General Test Requirements

Facility Pollutants

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
VOC	A
CO	A
NOX	A
PM	A
PM10	A
SO2	A
PB	B
H095	A
H021	B
H015	B
H114	B

Facility Pollutant Detail Information

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 1

1. Pollutant Emitted : VOC		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 2

1. Pollutant Emitted : CO		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 3

1. Pollutant Emitted :	NOX	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 4

1. Pollutant Emitted : PM		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 5

1. Pollutant Emitted : PM10		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 6

1. Pollutant Emitted :	SO_2	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

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D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 7

1. Pollutant Emitted : PB		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

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Effective : 3-21-96

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 8

1. Pollutant Emitted : H095		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 9

1. Pollutant Emitted : H021		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 10

1. Pollutant Emitted : H015		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 11

1. Pollutant Emitted : H114		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Appendix A
2. Facility Plot Plan :	Appendix B
3. Process Flow Diagram(s) :	Appendix C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	Appendix D
5. Fugitive Emissions Identification :	Appendix E
6. Supplemental Information for Construction Permit Applica	NA

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt	Appendix F
8. List of Equipment/Activities Regulated under	Appendix G
9. Alternative Methods of Operation :	Appendix H
10. Alternative Modes of Operation (Emissions	NA
11. Identification of Additional Applicable	Appendix I
12. Compliance Assurance Monitoring Plan :	Appendix J
13. Risk Management Plan Verification :	Appendix K
14. Compliance Report and Plan :	Appendix L
15. Compliance Certification (Hard-copy Require	Appendix M

Facility Supplemental Information

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 1

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 1 - 40 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 001 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : A	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : Natural gas or low sulfur distillate fuel oil fired. Unit information throughout application is based on baseload, ISO conditions, commensurate with ATC permit AC49-205703 and Title V permit 0970043-002-AV.		

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for natural gas and fuel oil firing.	
2. Control Device or Method Code :	28

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent) and the use of natural gas to control emissions.	
2. Control Device or Method Code :	30

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	23-Aug-1994
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : LM-6000
4. Generator Nameplate Rating : 40 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 367	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum heat input in field 1 is based on natural gas firing (LHV) at ISO conditions (base load). The max heat input for No. 2 distillate fuel oil firing is 372 MBtu/hour (LHV) at ISO conditions		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week
52 weeks/year	5,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

N/A - Facility is a Title V source

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

List of Applicable Regulations

See Appendix F for unit specific applicable requirements

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-1		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) N/A - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	65	feet
7. Exit Diameter :	10.0	feet
8. Exit Temperature :	718	°F
9. Actual Volumetric Flow Rate :	450000	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 447.722 North (km) : 3127.685		
14. Emission Point Comment :		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas. Proposed operation of this unit on natural gas is 5,000 hours per year based on a revised BACT analysis.	
2. Source Classification Code (SCC) : 2-01-002-01	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 0.39	5. Maximum Annual Rate : 1,970.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 1,034	
10. Segment Comment : (407 MBtu/h (HHV))/(1034 MBtu/mscf (HHV)) = 0.394 mscf/h (0.394 mscf/h)x(5000 h/yr)= 1970 mscf/yr Based on baseload, ISO conditions as in ATC permit. Ref: 1034 mmBtu/mscf based on permit app	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil. When natural gas is available, this unit is allowed to operate on No. 2 distillated fuel oil for 800 hours per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 2.87	5. Maximum Annual Rate : 2,296.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 138	
10. Segment Comment : (397 MBtu/h (HHV))/(138 MBtu/thousand gal (HHV)) = 2.87 thousand gal/h (2.87 thousand gal/h) x (800 h/yr)= 2296 thousand gal/yr Based on baseload, ISO Conditions REF: USEPA AP-42 for fuel oil.	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil. When natural gas is unavailable, this unit is allowed to operate on No. 2 distillated fuel oil for 1000 hours per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 2.87	5. Maximum Annual Rate : 2,870.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 138	
10. Segment Comment : (397 MBtu/h (HHV))/(138 MBtu/thousand gal (HHV)) = 2.87 thousand gal/h (2.87 thousand gal/h) x (1000 h/yr)= 2870 thousand gal/yr Based on baseload, ISO Conditions REF: USEPA AP-42 for fuel oil.	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	028		EL

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H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 63.0000000 lb/hour	121.5000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor 0 Reference : FIRE	Units :
7. Emissions Method Code : 0	

8. Calculations of Emissions :

Highest hourly emissions for either fuel:
Natural gas = 36 lb/h (@ 25 ppm)
Fuel oil = 63 lb/h (@ 42 ppm)

Potential hours of operation:
Natural gas = 5000 h/yr
Fuel oil = 1000 h/yr

Potential annual emissions:
[(36 lb/h x 5000 h/yr) + (63 lb/h x 1000 h/yr)] / (2000 lb/ton) = 121.5 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	25.00 ppm@15%O2
4. Equivalent Allowable Emissions :	36.00 lb/hour 90.00 tons/year
5. Method of Compliance : Condition A.6 of permit 0970043-0020-AV [AC49-205703].	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits for natural gas firing for 5000 h/yr. (36 lb/h x 5000 h/yr) / 2000 lb/ton = 90 ton/yr	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	63.00	lb/hour	25.20	tons/year
5. Method of Compliance : Condition A.6 of permit 0970043-0020-AV [AC49-205703].				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits are based on construction permit for No.2 distillate fuel oil firing for 800 h/yr (n.g. avail). (63 lb/h x 800h/yr) / 2000 lb/ton = 25.2 ton/yr				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	63.00	lb/hour	31.50	tons/year
5. Method of Compliance : Condition A.6 of permit 0970043-0020-AV [AC49-205703].				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits are based on construction permit for No.2 distillate fuel oil firing for 1000 h/yr (n.g. not avail). (63 lb/h x 1000 h/yr) / 2000 lb/ton = 31.5 ton/yr				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :			
2. Basis for Allowable Opacity :	OTHER		
3. Requested Allowable Opacity :			
Normal Conditions :	10	%	
Exceptional Conditions :	20	%	
Maximum Period of Excess Opacity Allowed :	6	min/hour	
4. Method of Compliance : Annual testing using USEPA Method 9			
5. Visible Emissions Comment : VE10 visible emission limits based on construction permit AC49-205703 (PSD-FL-182).			

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :	
2. Basis for Allowable Opacity :	RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour	
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity...	
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : TECO Model Number : 42D Serial Number : 42D-48216-280	
5. Installation Date :	01-Jun-1994
6. Performance Specification Test Date :	28-Dec-1995
7. Continuous Monitor Comment : OTHER: A continuous emission monitor required as a condition of construction permit AC49-205703 and 40 CFR Part 75.	

Continuous Monitoring System Continuous Monitor 2
:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Johnson Yokogawa Model Number : GR2400 Serial Number : 45VG0706	
5. Installation Date :	11-Nov-1995
6. Performance Specification Test Date :	11-Nov-1995
7. Continuous Monitor Comment : RULE: New Source Performance Standards, 40 CFR 60, Subpart GG.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Flow Technology Model Number : FT-20C3XBRLEA-5005 Serial Number : 2001833	
5. Installation Date :	01-Apr-1994
6. Performance Specification Test Date :	21-Dec-1994
7. Continuous Monitor Comment : Fuel oil flow monitor installed pursuant to 40 CFR Part 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Yokogawa Model Number : YF105NNNA3A5353CFMFF Serial Number : 4032B007	
5. Installation Date :	01-Apr-1994
6. Performance Specification Test Date :	21-Dec-1994
7. Continuous Monitor Comment : Natural gas flow monitor installed pursuant to 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Zerconium Oxide Model Number : 728 Serial Number : G-0407-948-E	
5. Installation Date :	01-Jun-1994
6. Performance Specification Test Date :	28-Dec-1995
7. Continuous Monitor Comment : OTHER: A continuous emission monitor required as a condition of construction permit AC49-205703 and 40 CFR Part 75..	

Continuous Monitoring System Continuous Monitor 6
:

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : TECO Model Number : 42D Serial Number : 42D-48216-280	
5. Installation Date :	01-Jun-1994
6. Performance Specification Test Date :	28-Dec-1995
7. Continuous Monitor Comment : OTHER: A continuous emission monitor required as a condition of construction permit AC49-205703 and 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 7

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : TECO Model Number : 42D Serial Number : 42D-48216-280	
5. Installation Date :	01-Jun-1994
6. Performance Specification Test Date :	28-Dec-1995
7. Continuous Monitor Comment : OTHER: A continuous emission monitor required as a condition of construction permit AC49-205703 and 40 CFR Part 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :

PM : C   SO2 : C   NO2 : C

4. Baseline Emissions :

PM :	0.0000 lb/hour	0.0000 tons/year
SO2 :	0.0000 lb/hour	0.0000 tons/year
NO2 :		0.0000 tons/year

5. PSD Comment :

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Appendix G
2. Fuel Analysis or Specification :	Appendix H
3. Detailed Description of Control Equipment :	Appendix I
4. Description of Stack Sampling Facilities :	Appendix J
5. Compliance Test Report :	Appendix K
6. Procedures for Startup and Shutdown :	Appendix L
7. Operation and Maintenance Plan :	Appendix M
8. Supplemental Information for Construction Permit Application :	NA
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

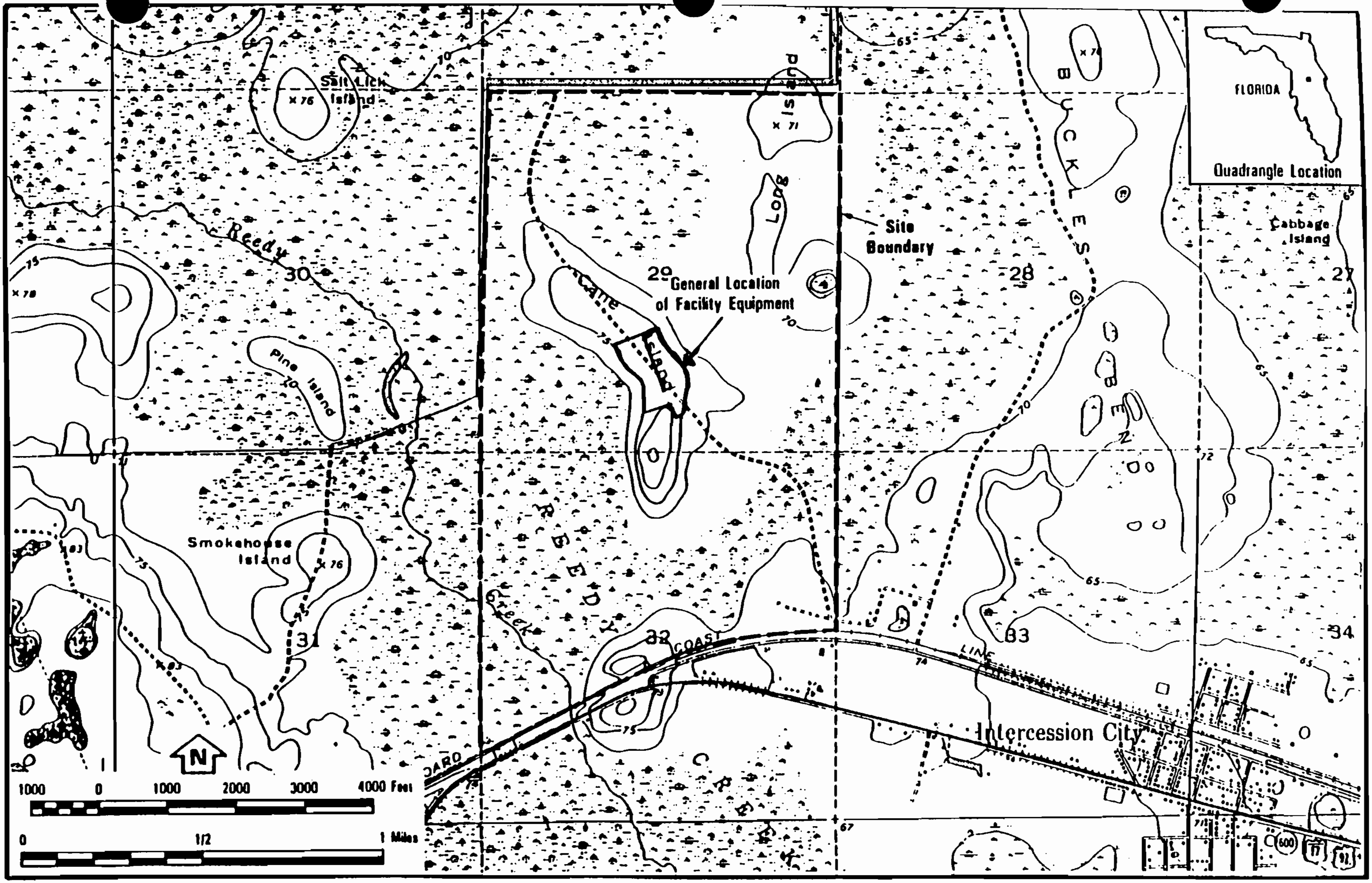
10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

Appendix A

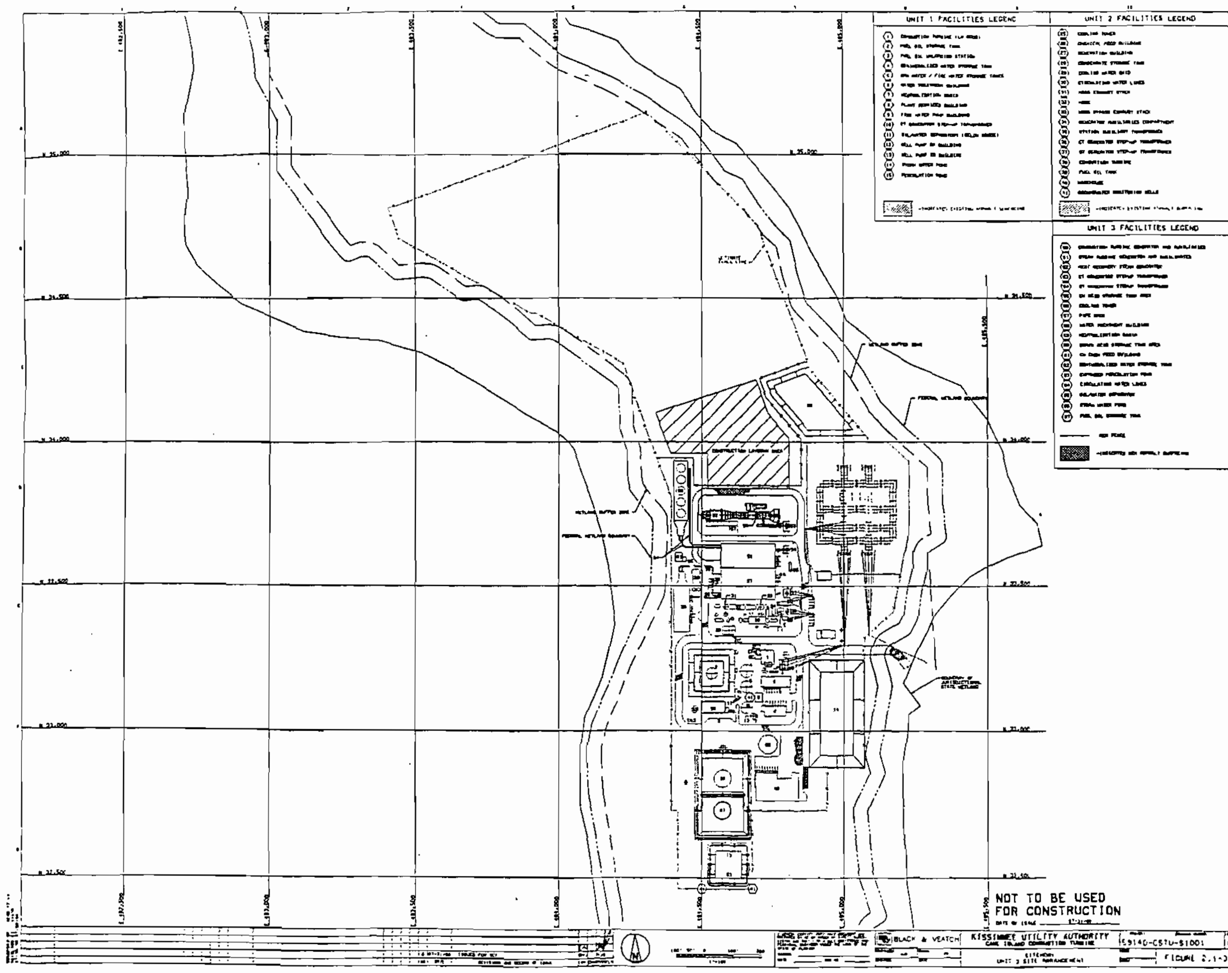


Base Map Source: USGS, Intercession City, Fl, 1970, quad.

CANE ISLAND SITE LOCATION

Appendix B

Best Available Copy



Appendix C

Appendix C

Process Flow Diagrams

(See individual unit process flow diagram contained in Appendix G)

Appendix D

Precautions to Prevent Emissions of Unconfined Particulate Matter

Facility Supplemental Information

Unconfined Particulate Matter Source	Precautions to Prevent and Control Unconfined Particulate Matter Emissions
Worker vehicle movements on-site	Paved roads and parking areas
Delivery vehicles (i.e., chemicals, fuel oil, consumable, trash, etc.)	Paved roads and parking areas

Appendix E

Fugitive Emissions Identification

Facility Supplemental Information

Fugitive Emission Source	Manner by which these fugitive emissions are addressed in this application
Worker and site vehicle movements on-paved roads	Total fugitive emissions (unconfined particulate matter) as the result of on-site vehicular traffic are estimated to be 0.005 tpy (see Appendix FF calculation sheet). Therefore, fugitive emissions are not required to be reported in accordance with Subsection III of the permit application instructions.
Delivery vehicles movements on-paved roads	
Fuel oil delivery by truck on paved roads	

Appendix F

Unit Specific Applicable Requirements

Applicable Regulation	Applicable Requirement	Compliance Status	Compliance Method
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.	Comply	Specific test methods and procedure requirements are outlined in the construction permit.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.	Comply	As specified in this section.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).	Comply	Specific emission limits and compliance methods established in the facility's construction permit.

40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.	Comply	Specific fuel limits and compliance methods established in the facility's construction permit.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.	Comply	As specified in this section.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: • For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. • For natural gas (no bulk storage), the values shall be determined and recorded daily.	Comply	For fuel oil, vendor will supply analysis with each delivery. For natural gas, vendor supplied analysis will be used to represent daily values.

	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334 (c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.	Will comply when applicable	As specified in this section.
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.	Comply	Specific test methods and procedure requirements are outlined in the facility's construction permit.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.	Will comply when applicable	As specified in this section.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.	Will comply when applicable	As specified in this section.

40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NOx and CO2 CEMS certification tests by Jan. 1, 1996.	Comply	Completed
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.	Comply	As specified in this section.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.	Comply	As specified in this section.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.	Comply	As specified in this section.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5 (f).	Comply	As specified in this section.

40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NOx continuous emission monitoring system (NOx pollutant monitor and an O2 or CO2 diluent gas monitor) with automated DAHS which records NOx concentration, O2 or CO2 concentration, and NOx emission rate.	Comply	As specified in this section.
	The owner or operator shall measure CO2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.	Comply	As specified in this section.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted according to the procedures in Appendix F of this subpart.	Comply	See applicable regulations in Appendix F for details.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.	Comply	As specified in this section.
40 CFR 75.11, Specific provisions for monitoring SO2	Gas and oiled fired units shall measure and record SO2 emissions as specified in 40 CFR 75, Appendix D.	Comply	See applicable regulations in Appendix D for details.

40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.	Comply	As specified in this section.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20 (b) and (c).	Will comply when applicable	As specified in this section.
	The owner or operator using the optional SO2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20 (g).		As specified in this section.
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.		As specified in this section.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24 (c) through (e), and repeat tests applicable to the "out-of-control" parameter.	Will comply when applicable	As specified in this section.

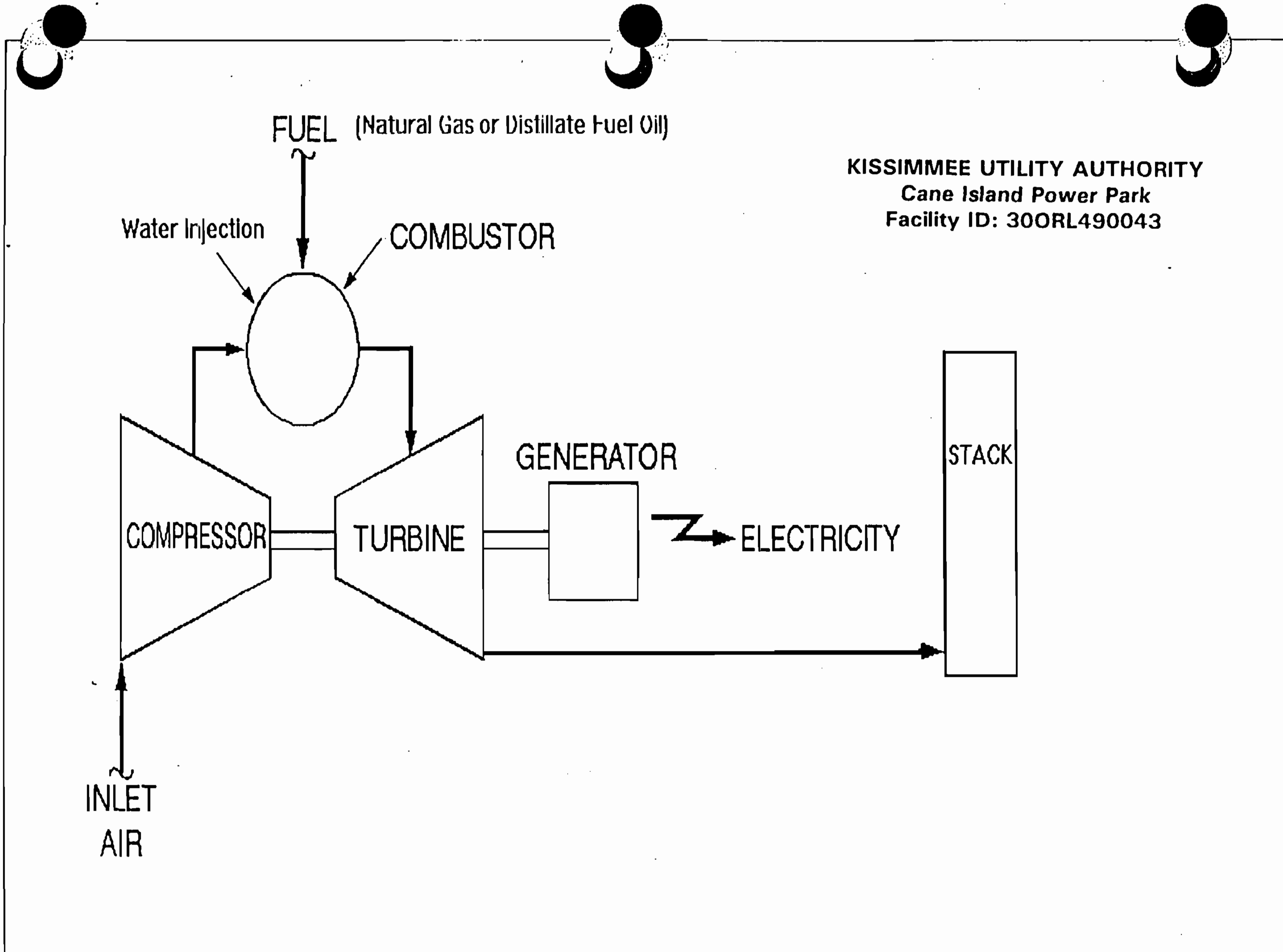
40 CFR 75.30 SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.	Comply	As specified in these sections.
40 CFR 75.51, SUBPART F - Recordkeeping Requirements, General recordkeeping provisions for specific situations	The owner or operator shall comply with the recordkeeping requirements of 40 CFR 75.51 (c)(1) through (3) when combusting natural gas and fuel oil.	Comply	As specified in this section.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52 (a)(1) through (3) and 40 CFR 75.52 (a)(5) through (7).	Comply	As specified in this section.
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.	Comply	As specified in this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of all applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.	Comply	As specified in these sections.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO2 emission records, The owner or operator shall record information as required in 40 CFR 75.55 (c) in lieu of the provisions of 40 CFR 75.54 (c),	Comply	As specified in this section.

40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56 (a)(1) through (3) and 40 CFR 75.56 (a)(5) through (7).	Comply	As specified in this section.
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60 (c) for any claims of confidential data.	Comply	As specified in this section.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.	Comply	As specified in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.	Comply	As specified in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.	Comply	As specified in this section.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this section.	Comply	As specified in this section.

40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.	Comply	As specified in this section.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.	Will comply when applicable	As specified in this section.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130	Will comply when applicable	As specified in this section.

F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.	Comply	Reporting.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.	Comply	As specified in this section.
Permit Number: AC 49-205703	The facility will comply with all operating restrictions, performance testing, and emission limits incorporated in the referenced permit.	Comply	As specified in this section.

Appendix G



40 MW Simple Cycle Combustion Turbine
Process Flow Diagram
(Ref DEP Form No. 62-210.900(1))

Appendix H

3075 CORNERS NORTH COURT
NORCROSS, GEORGIA 30091-5000
(770) 448-5235
(800) 241-6315

KISSIMMEE UTL AUTHORITY - CANE ISLAND
SCOTT YELVINGTON
P O BOX 423219
KISSIMMEE FL 34742-3219

Lab Number : 9568
Logged Date : 29-MAY-96
Sample Drawn : 28-MAY-96
Report Date : 31-MAY-96
Record Ref.# : 366310

Unit ID : UNIT 2
Sample ID : FUEL OIL #2
Worksite : CANE ISLAND
Time On Fluid :

Mfg. : UNKNOWN
Model : -
PO No.: 10114
Time On System :

TESTING PERFORMED:	MEASURED
Heat of Combustion Calc (Fuel oil) D4868	
Ash Content, % wt. - D482	0.001
Sulfur Content by XRF, % wt - D4294	0.03
Water Content KF (ppm) D1744	77
Density,Kg/L @ 15'C - D1298	00.8450
Gross Heat Value, BTU/gl - ASTM D4868	138064
Net Heat Value, BTU/gl - ASTM D4868	129550
Gross Heat Value, BTU/lb - ASTM D4868	19615
Net Heat Value, BTU/lb - ASTM D4868	18405
Arsenic, ppm, EPA 7060	<0000.05
Beryllium, ppm, EPA 7091	<0000.05
Mercury, ppm, EPA 7471	<0000.05
Lead, ppm, EPA 7421	0000.07

RECOMMENDATIONS / COMMENTS:

SAMPLE SUBMITTED AND PROCESSED FOR THE TEST DATA (ONLY).

Respectfully Submitted,

Analysts, Inc.

ANALYTICAL CHEMISTS ★ SINCE 1900 ★

NICHOLS LABORATORY, INC.

1924 Tennessee Avenue • Knoxville, Tennessee 37921 • (615) 523-6449

Certificate of Analysis

April 25, 1995

Power Generation Technologies
200 Tech Center Drive
Knoxville, TN 37912

Received: 4/20/95

Purchase Order No: ESC 05093

Lab ID # NF-2893

Sample ID # Kissimmee Utility Authority, Composite Sample
(50 ml each of ten samples)

	T -	60°F	70°F	100°F
1) Specific Gravity @ T	:	0.8475	0.8455	0.8412
2) Density @ T, g/cc	:	0.8467	0.8438	0.8412
3) Pounds Per U.S. Gallon @ T	:	7.0652	7.0408	6.9700
4) Gross Heating Value, Btu/lb	:	19505		
5) Btu Per Gallon	:	137,807		

Ref: ASTM D 1250 (tables); D 1298; D 4809-90.

Ultimate Analysis

6) % Carbon ....: 87.16

7) % Hydrogen ....: 12.68

8) % Nitrogen ....:< 0.50

9) % Sulfur ....: 0.0435

10) % Ash ....:< 0.001

11) % Oxygen by Difference ....: 0.00

Ref: ASTM D 129; D 482; D 5291

Sincerely yours,
Nichols Laboratory, Inc.

David V. Deitz
President

Microbac

Microbac Laboratories
ERIE TESTING LAB
1962 WAGER ROAD
ERIE PA 16509
(814)825-8533

AIR • FUEL • WATER • ... • ...

CERTIFICATE OF ANALYSIS

ENVIRONMENTAL SYSTEMS CORP.
200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
1	GAS 01, #1						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.32	%	4/25/95	15:00	EVM
	METHANE		95.33	%	4/25/95	15:00	EVM
	ETHANE		2.56	%	4/25/95	15:00	EVM
	PROPANE		0.67	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.15	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.06	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		<0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.68	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1041.89	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1023.76	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		939.43	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT.(LOW HEAT VAL)		923.08	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM
	ACTUAL NET BTU		939.43	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,986.10	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719717	G/ML	4/25/95	15:00	EVM
	DENSITY		0.04493573	LBS/CU.FT.	4/25/95	15:00	EVM
2	GAS 01, #2						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.49	%	4/25/95	15:00	EVM
	METHANE		95.24	%	4/25/95	15:00	EVM
	ETHANE		2.54	%	4/25/95	15:00	EVM

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ENVIRONMENTAL SYSTEMS CORP.
.
200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
2	GAS 01, #2						
	PROPANE		0.65	%	4/25/95	15:00	EVM
	I[illegible]TANE		0.19	%	4/25/95	15:00	EVM
	[illegible]NE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		<0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1039.41	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1021.32	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		937.17	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT.(LOW HEAT VAL)		920.86	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5874		4/25/95	15:00	EVM
	ACTUAL NET BTU		937.17	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,857.83	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719646	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044931297	LBS/CU.FT.	4/25/95	15:00	EVM
3	GAS 01-02, #3						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.35	%	4/25/95	15:00	EVM
	METHANE		95.31	%	4/25/95	15:00	EVM
	ETHANE		2.56	%	4/25/95	15:00	EVM
	PROPANE		0.67	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.14	%	4/25/95	15:00	EVM
	[illegible]PENTANE		0.06	%	4/25/95	15:00	EVM

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200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
3 GAS 01-02, #3						
N-PENTANE		0.03	%	4/25/95	15:00	EVM
[illegible]ES		<0.02	%	4/25/95	15:00	EVM
CARBON DIOXIDE		0.68	%	4/25/95	15:00	EVM
BTU, DRY (HIGH HEAT VAL)		1041.50	BTU/CU.FT.	4/25/95	15:00	EVM
BTU, SAT. (HIGH HEAT VAL)		1023.46	BTU/CU.FT.	4/25/95	15:00	EVM
NET BTU, DRY (LOW HEAT VAL)		939.15	BTU/CU.FT.	4/25/95	15:00	EVM
NET BTU, SAT.(LOW HEAT VAL)		922.81	BTU/CU.FT	4/25/95	15:00	EVM
REAL SPECIFIC GRAVITY		0.5876		4/25/95	15:00	EVM
ACTUAL NET BTU		939.15	BTU/CU.FT.	4/25/95	15:00	EVM
ACTUAL NET BTU		20,897.28	BTU/LB.	4/25/95	15:00	EVM
DENSITY		0.000719807	G/ML	4/25/95	15:00	EVM
DENSITY		0.044941301	LBS/CU.FT.	4/25/95	15:00	EVM
4 GAS 02, #4						
LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
NITROGEN		0.36	%	4/25/95	15:00	EVM
METHANE		95.36	%	4/25/95	15:00	EVM
ETHANE		2.55	%	4/25/95	15:00	EVM
PROPANE		0.65	%	4/25/95	15:00	EVM
ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
N-BUTANE		0.14	%	4/25/95	15:00	EVM
ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
N-PENTANE		0.03	%	4/25/95	15:00	EVM
HEXANES		<0.02	%	4/25/95	15:00	EVM
CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
[illegible] DRY (HIGH HEAT VAL)		1040.72	BTU/CU.FT.	4/25/95	15:00	EVM

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200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported	4/27/95
Date Received	4/21/95
Order No	9504-01099
Invoice No	038527
Cust #	005186
Sampled Date	4/12/95
Sampled Time	00:00
Sample Id	

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

ıP TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
GAS 02, #4						
TU, SAT. (HIGH HEAT VAL)		1022.61	BTU/CU.FT.	4/25/95	15:00	EVM
ET DRY (LOW HEAT VAL)		938.35	BTU/CU.FT.	4/25/95	15:00	EVM
ET BTU, SAT.(LOW HEAT VAL)		922.02	BTU/CU.FT	4/25/95	15:00	EVM
EAL SPECIFIC GRAVITY		0.5869		4/25/95	15:00	EVM
CTUAL NET BTU		938.35	BTU/CU.FT.	4/25/95	15:00	EVM
ıCTUAL NET BTU		20,901.34	BTU/LB.	4/25/95	15:00	EVM
ENSITY		0.000719852	G/ML	4/25/95	15:00	EVM
ENSITY		0.044894187	LBS/CU.FT.	4/25/95	15:00	EVM
GAS 02, #5						
LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
NITROGEN		0.53	%	4/25/95	15:00	EVM
METHANE		95.21	%	4/25/95	15:00	EVM
ETHANE		2.54	%	4/25/95	15:00	EVM
PROPANE		0.65	%	4/25/95	15:00	EVM
ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
N-BUTANE		0.14	%	4/25/95	15:00	EVM
ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
N-PENTANE		0.03	%	4/25/95	15:00	EVM
HEXANES		(0.02	%	4/25/95	15:00	EVM
CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
BTU, DRY (HIGH HEAT VAL)		1038.90	BTU/CU.FT.	4/25/95	15:00	EVM
BTU, SAT. (HIGH HEAT VAL)		1020.83	BTU/CU.FT.	4/25/95	15:00	EVM
NET BTU, DRY (LOW HEAT VAL)		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
NET BTU, SAT.(LOW HEAT VAL)		920.41	BTU/CU.FT	4/25/95	15:00	EVM
R ECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM

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ENVIRONMENTAL SYSTEMS CORP.
200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

MP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
5	GAS 02, #5						
	CTUAL NET BTU		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
	CT[illegible]ET BTU		20,844.55	BTU/LB.	4/25/95	15:00	EVM
	EN[illegible]		0.000719751	G/ML	4/25/95	15:00	EVM
	ENSITY		0.044937841	LBS/CU.FT.	4/25/95	15:00	EVM
7	GAS 03, #7						
	OWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	ITROGEN		0.50	%	4/25/95	15:00	EVM
	ETHANE		95.35	%	4/25/95	15:00	EVM
	THANE		2.49	%	4/25/95	15:00	EVM
	ROPANE		0.65	%	4/25/95	15:00	EVM
	SO-BUTANE		0.20	%	4/25/95	15:00	EVM
	-BUTANE		0.15	%	4/25/95	15:00	EVM
	SO-PENTANE		0.06	%	4/25/95	15:00	EVM
	-PENTANE		0.03	%	4/25/95	15:00	EVM
	EXANES		<0.02	%	4/25/95	15:00	EVM
	ARBON DIOXIDE		0.57	%	4/25/95	15:00	EVM
	TU, DRY (HIGH HEAT VAL)		1040.62	BTU/CU.FT.	4/25/95	15:00	EVM
	TU, SAT. (HIGH HEAT VAL)		1022.52	BTU/CU.FT.	4/25/95	15:00	EVM
	ET BTU, DRY (LOW HEAT VAL)		938.27	BTU/CU.FT.	4/25/95	15:00	EVM
	ET BTU, SAT. (LOW HEAT VAL)		921.94	BTU/CU.FT	4/25/95	15:00	EVM
	EAL SPECIFIC GRAVITY		0.5867		4/25/95	15:00	EVM
	CTUAL NET BTU		938.27	BTU/CU.FT.	4/25/95	15:00	EVM
	CTUAL NET BTU		20,988.20	BTU/LB.	4/25/95	15:00	EVM
	ENSITY		0.000718756	G/ML	4/25/95	15:00	EVM
	DEN[illegible]		0.044875676	LBS/CU.FT.	4/25/95	15:00	EVM

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Attn: James Sutton

ENVIRONMENTAL SYSTEMS CORP.

200 TECH CENTER DRIVE

KNOXVILLE TN 37912

Date Reported 5/15/95
Date Received 5/11/95
Order No 9505-00639
Invoice No 039261
Cust # 005186
Sampled Date 0/00/00
Sampled Time 00:00
Sample Id

Permit No
Cust P.O.

Subject: GAS SAMPLES (MILFORD PLANT, KISSIMMEE UTILITY), RECD.5/11

#	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
	MILFORD PLANT, 5/5/95 @ 07:00						
	WER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			5/12/95	10:00	EVM
	ITROGEN		1.82	%	5/12/95	10:00	EVM
	ETHANE		95.82	%	5/12/95	10:00	EVM
	TH[illegible]		2.16	%	5/12/95	10:00	EVM
	[illegible]		0.28	%	5/12/95	10:00	EVM
	SO-BUTANE		0.08	%	5/12/95	10:00	EVM
	-BUTANE		0.04	%	5/12/95	10:00	EVM
	SO-PENTANE		0.02	%	5/12/95	10:00	EVM
	-PENTANE		0.02	%	5/12/95	10:00	EVM
	EXANES		<0.02	%	5/12/95	10:00	EVM
	ARBON DIOXIDE		0.51	%	5/12/95	10:00	EVM
	TU, DRY (HIGH HEAT VAL)		1021.15	BTU/CU.FT.	5/12/95	10:00	EVM
	TU, SAT. (HIGH HEAT VAL)		1003.39	BTU/CU.FT.	5/12/95	10:00	EVM
	ET BTU, DRY (LOW HEAT VAL)		920.26	BTU/CU.FT.	5/12/95	10:00	EVM
	ET BTU, SAT. (LOW HEAT VAL)		904.24	BTU/CU.FT	5/12/95	10:00	EVM
	EAL SPECIFIC GRAVITY		0.5787		5/12/95	10:00	EVM
	CTUAL NET BTU		920.25	BTU/CU.FT.	5/12/95	10:00	EVM
	CTUAL NET BTU		20,785.00	BTU/LB.	5/12/95	10:00	EVM
	ENSITY		0.000704968	G/ML	5/12/95	10:00	EVM
	ENSITY		0.044264565	LBS/CU.FT.	5/12/95	10:00	EVM
2	KISSIMMEE UTILITY, CANE ISLAND GAS REG.. STATION, 5/9/95 @ 13:15 BY J. LOONEY						
	ULFUR, TOTAL (NATURAL GAS)	ASTM D1072-80			5/11/95	15:00	EVM
	TOTAL SULFUR		<1.0	GR/100CF	5/11/95	15:00	EVM
	TOTAL SULFUR (% BY WEIGHT)		<0.0031	%	5/11/95	15:00	EVM

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<0.0031%

Appendix I

Detailed Description of Control Equipment

1) Water Injection: A control technology used to limit NOx emissions. The thermal NOx contribution to total NOx emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used for both natural gas and oil firing.

2) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

Appendix J

2.0 Technical Approach

2.1 Particulate Sampling

2.1.1 Location of Traverse Points

To insure representative sampling of the stack the cross section was divided into discreet sampling points according to the procedures described in 40 CFR 60: Appendix A, Method 1, Sample and Velocity Traverses for Stationary Sources. The sampling points were located on two perpendicular diameters of the stack, and each diameter was divided into twelve sampling points. During the one hour compliance test runs for PM, the stack gas characteristics (i.e., flow, temp.) were audited every 5 minutes. Figure 1 shows the layout of the stack and the locations of the sampling points.

2.1.2 Velocity and Volumetric Flow Measurements

Velocity measurements were performed for the PM isokinetic sampling train using the procedures outlined in 40 CFR, Part 60, Appendix A, Method 2, Determination of Stack Gas Velocity and Volumetric Flow Rate, during each compliance test run. The velocity pressures were measured using an "S"-type pitot tube and a standard oil filled manometer. The calibration procedures for the pitot tubes are included in Appendix C.

2.1.3 Temperature Measurements

The temperature of the stack gas was measured using K-type thermocouples and dedicated digital temperature readouts. The isokinetic sampling train was equipped with a thermocouple. The temperature was recorded on the sampling data sheet at each traverse point location. The stack temperatures were arithmetically averaged and used to calculate the volumetric flow rates at standard and dry standard conditions. Detailed accuracy and calibration information is described in Section 4.2.2. Calibration data sheets are included in Appendix C.

2.1.4 Carbon Dioxide and Oxygen

The CO_2 and O_2 stack gas concentrations were determined according to procedures specified in CFR 40, Part 60, Appendix A, Method 3A, Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure). Figure 3 is a schematic of the CEM sampling system. Access to the stack was through a sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample

STARTING DATE:	DATE LAST REV.: 12/20/94	DRAF CK.BY: R.MOORE	INITIATOR: J. KELLEY	DWG. NO.:
DRAWN BY: M. MOWERY	DRAWN BY: T. GREGG	ENG. CHCK. BY: R. MOORE	PROJ. MGR.: J. KELLEY	PROJ. NO.: 410226

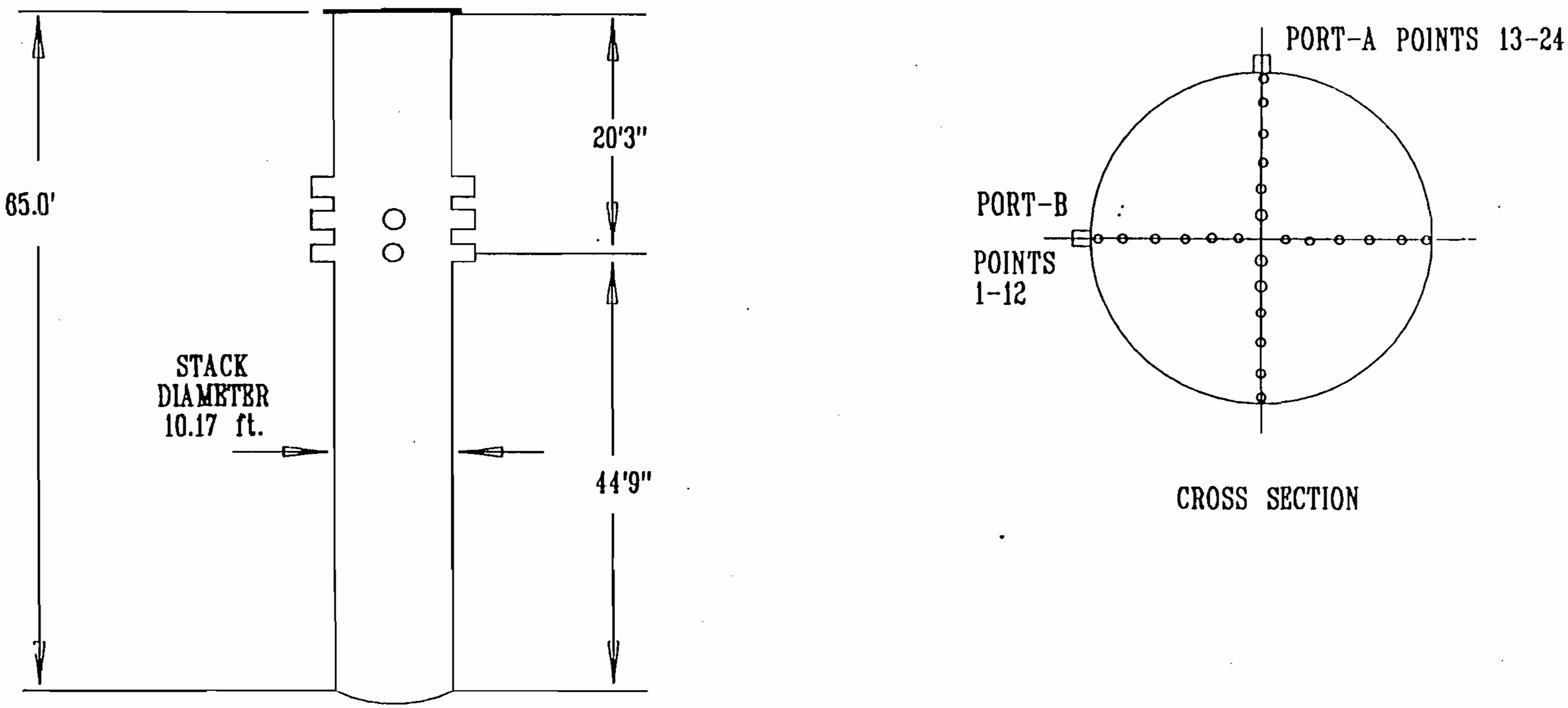

FIGURE 1

SCHEMATIC OF STACK & SAMPLING PORTS
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from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The O_2 analyzer used was manufactured by Teledyne, model number 90. The CO_2 analyzer used was manufactured by Horiba, model number PIR 2000. The O_2 and CO_2 analyzer was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded the concentrations on a one minute average. Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the both analyzers. The analyzers were calibrated daily before and after each test run with Protocol 1 gases. The O_2 analyzer was calibrated using the following concentrations of O_2 gas: 10 % and 15.96 %. The CO_2 analyzer was calibrated using the following concentrations of CO_2 gas: 2.99 % and 9.95 %. The calibration gas certification sheets can be found in Appendix B.

2.1.5 Moisture Determinations

The moisture content of the stack gas was determined using procedures outlined in 40 CFR 60; Appendix A, Reference Method 4, Determination of Moisture in Stack Gases. The Method 4 sampling was incorporated into the PM isokinetic sampling train for all six compliance test runs.

The moisture was determined for each sampling run by gravimetrically measuring the weight gain of the chilled impingers over the length of the sampling runs. This weight gain was used in calculations in conjunction with the corrected sample volume to determine the moisture percentage in the stack gas.

2.1.6 Particulate Sampling Procedure

The particulate sampling was performed using the sampling procedures described in 40 CFR, Part 60; Appendix A, Reference Method 5, Determination of Particulate Emissions From Stationary Sources. To measure particulate emission rates and concentrations, a slip stream was withdrawn isokinetically from the source and collected on a heated filter and drawn through a series of chilled impingers. A schematic of the sampling train is shown in Figure 2.

The general sampling procedures were performed in accordance with EPA Reference Method 5. The equipment used to perform the sampling was produced by Anderson Samplers, Inc.

STARTING DATE: 7/14/93	DATE LAST REV.: 12/21/94	DRAFT.CHCK. BY: R. MOORE	INITIATOR: J.KELLEY	DWG. NO.:
DRAWN BY: M. MOWERY	DRAWN BY: T.GREGG	ENG. CHCK. BY: D. KING	PROJ. MGR.: J.KELLEY	PROJ. NO.: 410226

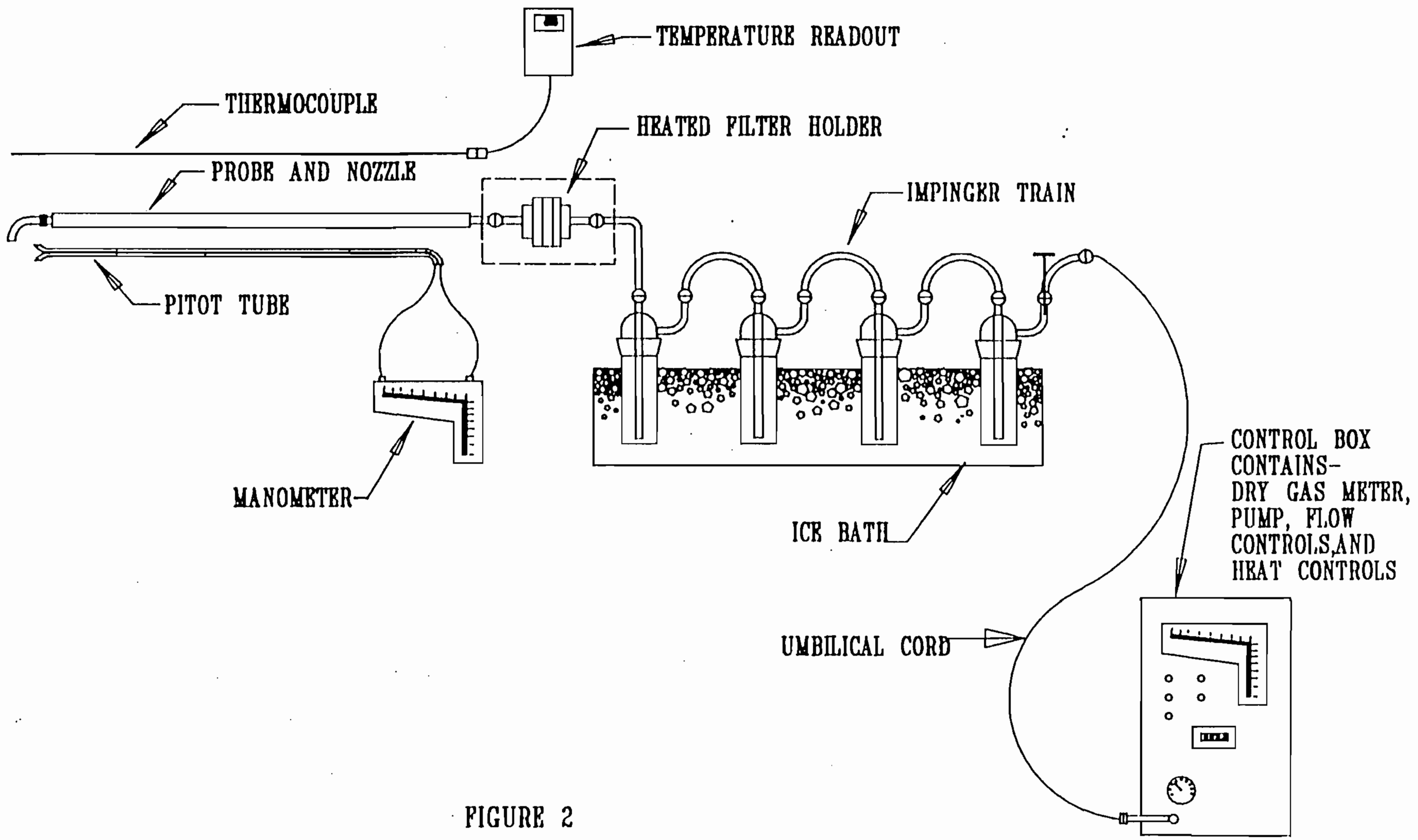

FIGURE 2

SCHEMATIC OF METHOD 5 PARTICULATE TRAIN
KISSIMEE UTILITY AUTHORITY
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and NuTech Corporation. The equipment has the approval of and meets the standards of calibration accuracy as set forth by EPA.

The sampling equipment consists of three main units: the pump, control units and sampling train. The pump is a Gast® lubricated fiber vane rotary pump altered for leak-free operation. The pump is connected to the control unit, which contains a Rockwell dry gas meter, dual manometers, and a calibrated orifice system designed to enable isokinetic sampling. The sampling train is connected to the control unit by means of a flexible umbilical cord, and contains the impinger case, filter oven, stainless steel sampling nozzle and glass probe.

The probe used was constructed of glass wrapped with a heating element and incased in a 304 stainless steel tube. The heating element maintains probe temperatures above the gaseous dew point of the stack gas and prevents condensation of moisture or acid gases in the probe. The probe was rigidly mounted to the sampling oven and was directly connected to a heated glass fiber filter. The filter was placed on a glass frit and housed in a glass filter bell and teflon support housing. The filter oven temperature was maintained between 225 and 275 °F throughout the sampling runs.

Four ball-topped impingers in an ice bath were connected to the back of the filter. The first impinger was initially empty and was used as a moisture trap. The second and third impingers each contained a 100 ml solution of water. The fourth impinger contained indicating silica gel, weighed to the nearest 0.1 gram. The impinger section of the train was assembled in a dedicated clean area prior to being taken to the stack where the probe and filter were attached to the train. All fittings in the system were rigid ground glass to glass to prevent leakage.

The stack sample was drawn isokinetically through a glass nozzle, the heated probe and into the heated filter assembly, where the particulate matter was collected on a preweighed filter. The filtered gas then passed through the impinger system which condensed moisture and collected any vapor phase materials which may have passed through the filter. The dry, cooled gas stream then passed through the umbilical cord to the dry gas meter, orifice and pump.

The velocity and stack temperature were monitored at each sampling point to insure that isokinetic sampling rates were maintained. Leak checks were performed prior to sampling, and again immediately after removing the probe from the stack, before the sampling train was moved to the other sampling port. All leak checks were performed as specified in Method 5. After the sampling train was positioned at the second sampling port, it was leak checked again to ensure no leak had developed during the transfer of the train from one port to the other. At the conclusion of the sampling run the train then had to pass a final leak check before sample recovery procedures were initiated.

2.2 Nitrogen Oxides (NOx) Continous Emission Monitoring

The stack gases from Gas Turbine Unit #1 were sampled for nitrogen oxides (NO_x) concentration using a Thermo Electron Model 10A Chemilüminescent NO-NO_x Gas Analyzer. Figure 3 shows a schematic of the CEM sampling system. The key components of this analyzer include the reaction chamber, the photomultiplier tube, and the ozonator. The cylindrical reaction chamber is where sample gas containing NO molecules mixes with O_3 molecules from the ozonator. Electronically excited NO_2 molecules are created which emit light (chemiluminescence) as the orbital electrons decay to their ground states. The chemiluminescence is monitored through an optical filter by a high-sensitivity photomultiplier tube positioned at one end of the reactor. The filter-photomultiplier combination responds to light in a narrow wavelength band unique to the desired electron decay. Sample flow is controlled so that the output from the photomultiplier tube is linearly proportional to the NO concentration. The basic chemiluminescent analyzer is only sensitive to NO molecules. To measure NO_x (i.e., NO_2 plus NO) the NO_2 must first be converted to NO. The conversion is accomplished by passing the sample gas through a temperature controlled chamber which disassociates NO_2 to NO plus oxygen.

NO_x sampling was performed in accordance with the procedures presented in EPA Method 20. Access to the stack was through a heated sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The NO_x monitor was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded concentrations on a one minute average.

STARTING DATE: 7/29/93	DATE LAST REV.: 12/21/94	DRAFT. CHCK. BY: R. MOORE	INITIATOR: J.KELLEY	DWG. NO.:
DRAWN BY: R. BRYSON	DRAWN BY: T.GREGG	ENG. CHCK. BY: R. MOORE	PROJ. MGR.: J.KELLEY	PROJ. NO.: 410226

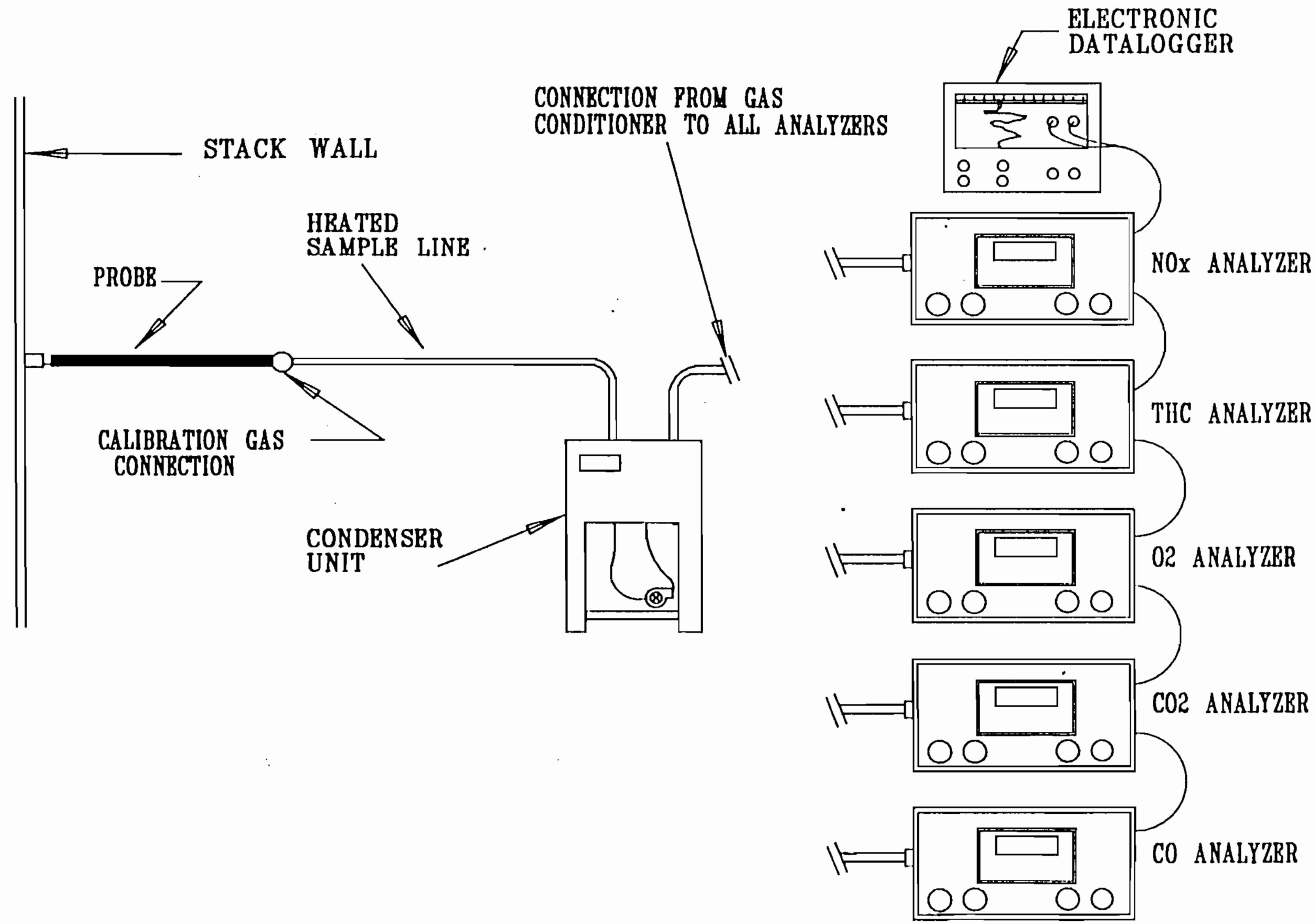


FIGURE 3

SCHEMATIC OF TYPICAL CONTINUOUS EMISSION MONITOR
KISSIMEE UTILITY AUTHORITY
IT PROJECT NO. 410226

IT INTERNATIONAL TECHNOLOGY CORPORATION

Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the NO_x monitor. The NO_x monitor was calibrated daily before and after each test run. These calibrations consisted of introducing prepurified nitrogen as a zero gas and three known concentrations of Protocol 1 NO_x. The specific calibration gas concentrations were 25.85 ppm, 46.12 ppm, and 85.8 ppm. The Protocol 1 calibration gas certification sheets can be found in Appendix B.

Bias checks were also performed in conjunction with the monitor calibrations. These checks were performed by introducing calibration gas at the point of sample extraction on the stack. This allowed calibration gases to travel through the complete NO_x monitoring system.

Response time tests were performed prior to any sampling being performed. Alternating the introduction of span and zero calibration gas during the bias checks three times and recording the time required for the monitor to reach 95 percent of the final stable value enabled the determination of mean upscale and downscale response times.

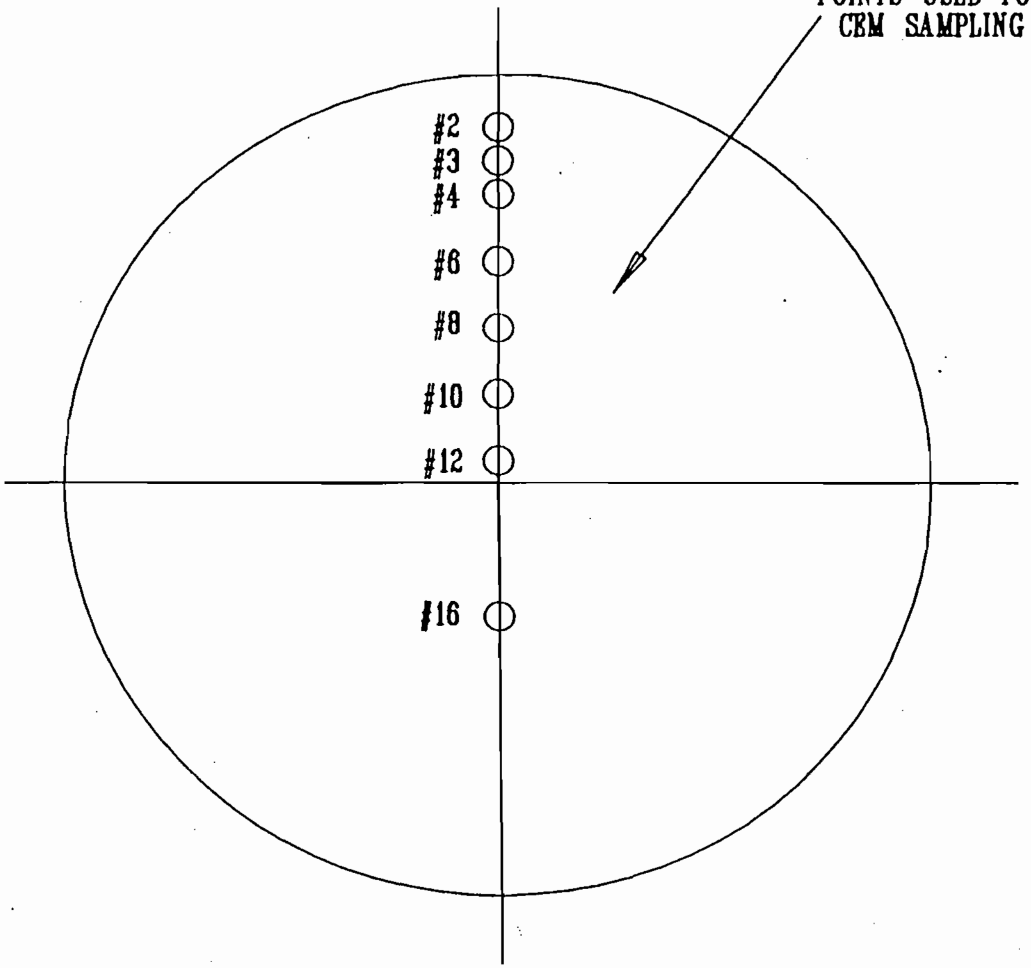
Zero and calibration drift were also determined for each run of the testing. This was accomplished by comparing zero and upscale calibrations from before and after each test run.

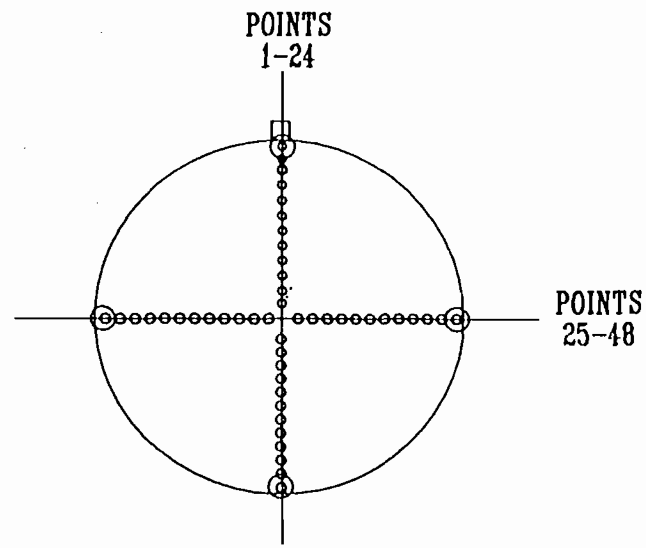
Calibration of the NOx analyzer was performed using three up scale span gases and a zero gas. Calibration of the NOx analyzer was performed before and after each test run.

Before and after each test run, system bias checks were performed by introducing calibration gases at the point where stack gases were being extracted from the source. This enabled the evaluation of the affects of the sampling system (Teflon® line and gas conditioning system) on the response of the analyzer. Instrument calibrations were compared before and after each test run to determine the calibration and zero drift.

A preliminary O_2 traverse was conducted for the purpose of selecting sampling points of low O_2 and high CO_2 concentrations. The traverse for primary diluent sampling was conducted at 30% of full load. The number of sample points used was 48 as shown in Figure 4. The minimum sampling time at each point was 94 seconds (60 seconds + 34 second response time). The diluent sampling results for the 48 traverse points are summarized in Figure 5. The eight sampling points that were chosen for sampling based on diluent conditions are also depicted in Figure 4. Each of the eight points was sampled for 7.5 minutes during each of

STARTING DATE:	DATE LAST REV.: 12/21/94	DRAF[illegible]K.BY: R. MOORE	INITIATOR: J. KELLEY	DWG. NO.:
DRAWN BY: M. MOWERY	DRAWN BY: T. GREGG	ENG. CHCK. BY: R. MOORE	PROJ. MGR.: J. KELLEY	PROJ. NO.: 410226





CROSS SECTION

DISTANCE INSIDE STACK

POINT #

#2 = 15.4"
#3 = 18.2"
#4 = 21.1"
#6 = 27.6"
#8 = 35.2"
#10 = 44.7"
#12 = 60.1"
#16 = 105.4"

FIGURE 4

SCHEMATIC OF STACK & SAMPLING PORTS FOR CEMS
KISSIMEE UTILITY AUTHORITY
IT PROJECT NO. 410226

IT INTERNATIONAL TECHNOLOGY CORPORATION

Preliminary Diluent Traverse Data
Figure #5

PROJECT NAME:	Kissimee Utility Authority
PROJECT NUMBER:	410226
LOCATION:	Kissimee,Fla.
DATE:	11-07-94

Sample Point	Diluent Concentration,% O_2	CO_2
1	15.85 %	2.4 %
2	15.74 %	2.5 %
3	15.74 %	2.5 %
4	15.74 %	2.5 %
5	15.84 %	2.3 %
6	15.75 %	2.5 %
7	15.80 %	2.3 %
8	15.75 %	2.5 %
9	15.77 %	2.4 %
10	15.76 %	2.5 %
11	15.80 %	2.4 %
12	15.74 %	2.5 %
13	15.82 %	2.4 %
14	15.82 %	2.4 %
15	15.78 %	2.3 %
16	15.75 %	2.5 %
17	15.81 %	2.3 %
18	15.82 %	2.3 %
19	15.85 %	2.4 %
20	15.79 %	2.3 %
21	15.85 %	2.4 %
22	15.84 %	2.4 %
23	15.79 %	2.3 %
24	15.86 %	2.5 %
25	15.81 %	2.5 %
26	15.82 %	2.4 %
27	15.85 %	2.5 %
28	15.79 %	2.3 %
29	15.85 %	2.5 %
30	15.84 %	2.4 %
31	15.79 %	2.4 %
32	15.86 %	2.3 %
33	15.79 %	2.5 %
34	15.85 %	2.5 %
35	15.84 %	2.4 %
36	15.79 %	2.5 %
37	15.86 %	2.3 %
38	15.81 %	2.5 %
39	15.82 %	2.3 %
40	15.85 %	2.5 %
41	15.79 %	2.4 %
42	15.86 %	2.4 %
43	15.81 %	2.3 %
44	15.82 %	2.5 %
45	15.85 %	2.5 %
46	15.79 %	2.4 %
47	15.85 %	2.5 %
48	15.84 %	2.3 %

the 1 hour compliance test runs and for at least 2.5 minutes during each of the Subpart GG test runs.

2.3 Total Hydrocarbon Sampling Procedures

Sampling for total hydrocarbons (THC) was performed according to the method described in the U.S. EPA Code of Federal Regulations, Reference Method 25A, Determination of Total Gaseous Organic Concentration using a Flame Ionization Analyzer. Figure 3 is a schematic of the CEM sampling system. Access to the stack was through a heated sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The THC analyzer used was manufactured by J.U.M. Engineering, model number VE-7. The THC monitor was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded the concentrations on a one minute average. Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the THC analyzer. The THC monitor was calibrated daily before and after each test run with Protocol 1 gases. The THC analyzer was calibrated using the following concentrations of propane gas: 24.8 ppm, 55.43 ppm, and 84.81 ppm. The Protocol 1 calibration gas certification sheets can be found in Appendix B.

2.4 Carbon Monoxide Sampling Procedures

Sampling for carbon monoxide (CO) was performed according to the method described in the U.S. EPA Code of Federal Regulations, Reference Method 10, Determination of Carbon Monoxide Emissions from Stationary Sources. Figure 3 is a schematic of the CO CEM sampling system. Access to the stack was through a heated sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The CO analyzer used was manufactured by TECO, model number 48. The CO analyzer was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded the concentrations on a one minute average. Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the CO analyzer. The CO analyzer was calibrated daily before and after each test run with Protocol 1 gases. The CO analyzer was calibrated using the following concentrations of carbon monoxide gas: 47.01 ppm and 85.05 ppm. The Protocol 1 calibration gas certification sheets can be found in Appendix B.

2.5 Visible Emission Testing Procedures

Sampling for carbon monoxide (CO) was performed according to the method described in the U.S. EPA Code of Federal Regulations, Reference Method 9, Visual Determination of the Opacity of Emissions from Stationary Sources. A one hour visible emission (VE) test was conducted for each PM test run while the unit was operating at full load. The VE testing was conducted simultaneously with the NO_x, CO, PM and THC sampling.

2.6 SO_2, As, Be, Pb Fuel Sampling Procedures

Sulfur Dioxide emissions have been calculated using the fuel analysis data included in Appendix B. Analytical method ASTM D4294 was used to determine the sulfur content of the #2 distillate fuel, while ASTM D3246-81 was used to determine the sulfur content of the natural gas. Analytical method ASTM D 5056 was used to determine the concentration of arsenic, beryllium, mercury, and lead in the #2 distillate fuel.

Appendix K

Compliance Test Report

The air construction permit (AC49-205703) contains several specific conditions relating to the performance of emissions compliance testing at the KUA Cane Island Power Park. The conditions relate to notification and reporting procedures and emission compliance test methods. The specific conditions relating to compliance testing listed in the aforementioned permit are provided below. A table showing the dates when each of these requirements were completed is provided following the conditions.

Notification/Reporting Requirements

Specific Condition 8: Compliance with the NOx, SO2, CO, PM, PM10, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July 1991 version) and adopted by reference in F.A.C. Rule 17-2.700.

Method 1	Sample and Velocity Traverse
Method 2	Volumetric Flow Rate
Method 3	Gas Analysis
Method 5/17	Determination of Particulate Emissions from Stationary Sources
Method 9	Visual Determination of the Opacity of EMissions from Stationary Sources
Method 8	Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources (for fuel oil firing only)
Method 10	Determination of Carbon Monoxide Emissions from Stationary Sources
Method 20	Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbine
Method 25A	Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer

Other DEP approved methods may be used for compliance testing after prior Departmental approval.

Specific Condition 9: Method 5 or 17 must be performed on each unit to determine the initial compliance status of particulate matter emissions of the unit. Thereafter, the opacity emissions test may be used unless 10 percent opacity is exceeded.

Specific Condition 10: Compliance with the SO2 emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of the liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuels.

Specific Condition 11: Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

Specific Condition 12: Mercury (Hg) shall be testing during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

Specific Condition 13: During performance tests, to determine compliance with the allowable Nox standard, measured NOx emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor.

Specific Condition 19: The sources shall comply with all requirements of 40 CFR 60, Subpart GG, and F.A.C. Rule 17-296.800, Standards of Performance for Stationary Gas Turbines.

<u>Test Methods</u>

Specific Condition 14: Test results will be the average of 3 valid runs. The Central District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources shall operate between 95% and 100% of permitted capacity during the compliance test(s) as adjusted for ambient temperature. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

Compliance Dates

Activity	Related Permit Condition	Unit 1 Date	Unit 2 Date
Initial Startup	8	8/20/94	1/29/95
Notification of Testing	14	9/23/94	3/2/95
Compliance Testing	8, 14	10/20/94 11/3/94* 11/7/94*	4/6-10/95
Submittal of Test Report	14	12/22/94	5/24/95
*KUA received permission from FDEP to retest. Retesting performed on these dates.			

Compliance Test Methods

The compliance testing was done in accordance with the permit requirements listed above. The compliance test methods and results are provided in the test reports provided to the FDEP on the dates in the above table.

Appendix L

Procedures for Startup and Shutdown

After a normal start up is initiated, the time is documented when the turbine starts firing. The turbine then continues with a normal start up and warm up. Time is again documented again when the breaker closes. Upon the generator reaching nine MW, the water injection pump is turned on, and flow is established to the turbine. When the NOx emissions are controlled and stable (20-24 ppm), the time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to nine MW and the water injection pumps are taken out of service (this time is documented). Time is again recorded when the turbine stops firing.

Appendix M

Operation and Maintenance Plan

An operation and maintenance plan will be submitted if required by FDEP.

Z 031 392 023

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to A K Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	11-24-99

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. A.K. Sharma, Director
KUA
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

4a. Article Number
Z 031 392 023

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
11/29/99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Beatriz Dyer

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

Thank you for using Return Receipt Service.

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
DEC 01 1999
BUREAU OF AIR REGULATION

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Clair Fancy, DARM, MS 5505

2. ____

3. AL

4. ____

5. ____

PLEASE PREPARE REPLY FOR:	COMMENTS:
____ SECRETARY'S SIGNATURE	Final Order Approving Certification for the Kissimmee Utility Authority's / FMPA's Cane Island Power Park is enclosed.
____ DIV/DIST DIR SIGNATURE	
____ MY SIGNATURE	
____ YOUR SIGNATURE	
____ DUE DATE ____	
ACTION/DISPOSITION	
____ DISCUSS WITH ME	
____ COMMENTS/ADVISE	
____ REVIEW AND RETURN	RECEIVED
____ SET UP MEETING	NOV 24 1999
____ FOR YOUR INFORMATION	BUREAU OF AIR REGULATION
____ HANDLE APPROPRIATELY	
____ INITIAL AND FORWARD	
____ SHARE WITH STAFF	
____ FOR YOUR FILES	

FROM: M. Morahan DATE: 11/23/99 PHONE: 1-9720

DEP 15-026 (12/93) OGC-TT

no green card

Z 031 392 007

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Tim Hellman	
Street & Number Black & Veatch	
Post Office, State, & ZIP Code Kansas City FL	
Postage	$ 0
Certified Fee	KUA
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date PSD-FL-254 DA 98-38	11-15-99

PS Form **3800**, April 1995

Z 333 612 591

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Doug Neeley	
Street & Number US EPA	
Post Office, State, & ZIP Code Atlanta GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date KUA CI Unit 3 P50-F1-254	1-12-99

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Doug Neeley, Chief
Air Branch
US EPA Region IV
61 Forsyth St.
Atlanta, GA 30303

4a. Article Number
Z 333 612 591

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)* JOYCE EVANS

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)* JAN 15 1999
X

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

Thank you for using Return Receipt Service.

Best Available Copy

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
JUN 9 1999
BUREAU OF

RECEIVED
JUN 9 1999
BUREAU OF
AIR REGULATION

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-254

Kissimmee Utility Authority
Cane Island Power Park Unit No. 3
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to The Kissimmee Utility Authority (KUA). The permit is to construct: a nominal 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine with a heat recovery steam generator and supplemental duct burners; a 1.0 million gallon fuel oil storage tank; a 130-foot main stack; and a 100 foot bypass stack at the Cane Island Power Park at 6075 Old Tampa Highway, Osceola County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NOx), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are The Kissimmee Utility Authority, 1701 West Carroll Street, Kissimmee, Florida 34741-6804.

The new unit will be a General Electric PG7241FA combustion turbine-electrical generator which will generate 167 MW (nominal) in simple cycle mode or 250 MW in combined mode. The unit will operate primarily on natural gas and will be permitted to operate 8760 hours per year of which no more than 720 will be on 0.05 percent sulfur distillate fuel oil. The supplemental duct burners will operate only during high ambient temperature and will partially compensate for lower power capacity achievable at high temperature.

NOx emissions will be controlled by Dry Low NOx (DLN) combustors capable of achieving emissions of 9 parts per million by volume at 15 percent oxygen. Lower emission limits will apply if the KUA chooses selective catalytic reduction in lieu of or in conjunction with DLN technology. NOx will be controlled under the minimal back-up fuel oil operation by water or steam injection. SO_2 and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC will be controlled by good combustion practices. Emissions of CO will be similarly controlled unless the KUA chooses to install an oxidation catalyst.

The maximum emissions in tons per year based on the original application and prior to final selection of the combustion turbine are summarized below. NOx, VOC, and CO emissions will be substantially lower as a result of the emissions characteristics of the GE combustion turbine selected since receipt of the application and the Department's proposed BACT determination .

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	109	25/15
SO_2	38	40
NO_x	823	40
VOC	173	40
CO	3818	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

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

This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3).

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

Dept. of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-5963

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741-6804
Telephone: 407/933-7777
Fax: 407/847-0787

The complete project file includes the Draft Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Z 333 612 586

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to A K Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date PSD-Fl-254 PA 98-38 C I PP Unit 3	1-7-99

PS Form **3800**, April 1995

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. A.K. Sharma, PE
Kissimmee Utility Auth.
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

4a. Article Number
Z 333 612 586

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
1/11/99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Manuel [illegible]

Is your **RETURN ADDRESS** completed on the reverse side?

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

● Print your name, address, and ZIP Code in this box ●

RECEIVED
JAN 13 1999
BUREAU OF
AIR REGULATION

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
JAN 1[illegible] 1999
BUREAU OF
AIR REGULATION

Z 333 612 518

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to A K Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 9-24-98 PA 98-38 PSD-Fl-254	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. A. K. Sharma, PE
Director of Power Supply
Kissimmee Utility Auth.
PO Box 423219
Kissimmee, Fl 34742-3219

4a. Article Number Z333 612 518

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 9-29-98

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X [signature]

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

Thank you for using Return Receipt Service.

UNITED STATES POSTAL SERVICE

ORLANDO FL 328
PM
29 SEP

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

RECEIVED
OCT 02 1998
BUREAU OF
AIR REGULATION

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

P 265 659 407

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to A. K. Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee. Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date PSD-F1-254 pa 98-38	8/18/98

PS Form **3800**, April 1995

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
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- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
A.K. Sharma, PE
Director of Power Supply
Kissimmee U. Authority
PO BOX 423219
Kissimmee, Fl 34742-3219

4a. Article Number
P265 659 407

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
8-21-98

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X [illegible signature]

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
AUG 24 1998
BUREAU OF
AIR REGULATION

Z 031 391 907

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to A K Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 12-20-99 09100043-007-AC PSD-F1-182A	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
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- Attach this form to the front of the mailpiece, or on the back if space does not permit.
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- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
A.K. Sharma
KUA
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

4a. Article Number
Z 031 391 907

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
12/22/99

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X [signature]

8. Addressee's Address *(Only if requested and fee is paid)*

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

Thank you for using Return Receipt Service.

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED

DEC 27 1999

BUREAU OF AIR REGULATION

Z 031 392 005

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to A K Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-10-99 PSD-Fl-182A Cane Island PP	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
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I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
A. K. Sharma
KUA
1701 W. Carroll St.
Kissimmee, Fl
34641-6804

4a. Article Number
Z 031 392 005

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
11/12/99

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X Manuel [illegible]

8. Addressee's Address *(Only if requested and fee is paid)*

Thank you for using Return Receipt Service.

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

UNITED STATES POSTAL SERVICE

ORLANDO FL 328
PM
13 NOV
1999

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED
NOV 16 1999
BUREAU OF AIR REGULATION

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Kissimmee Utility Authority, Cane Island Power Park
DEP File No. PSD-FL-182A, 0970043-007-AC
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue a modification of a Prevention of Significant Deterioration (PSD) Permit to Kissimmee Utility Authority (KUA) for its Cane Island Power Park located in Osceola County. A Best Available Control Technology (BACT) determination was required for this modification pursuant to Rule 62-212.400, F.A.C. Prevention of Significant Deterioration (PSD). The applicant's name and address are: Kissimmee Utility Authority, 1701 West Carroll Street, Kissimmee, Florida 34741.

This is an existing facility consisting of a 40 Megawatt simple cycle combustion turbine (Unit 1) as well as a 120 Megawatt combined cycle unit (Unit 2). Both units fire natural gas and No. 2 fuel oil with gas/oil heat inputs of 367/372 and 869/928 MMBtu/hr respectively (at an ambient temperature of 59°F). These units have a Title V permit (0970043-001-AV) issued by the State of Florida.

The permitted emission rates of nitrogen oxides (NOx) for Units 1 and 2 while firing gas/oil are 25/42 ppm and 15/42 respectively. On an annual basis the permitted tons per year (TPY) of potential NOx emissions are 171.2 and 290.6 respectively. Effective January 1, 2000 the permitted NOx emission rate for Unit 1 decreases to 15 ppm while firing natural gas firing, causing the potential TPY of NOx to equal to 116.9 (a reduction of 54.3 TPY).

KUA requests that the aforementioned NOx emission rate for Unit 1 remain at 25 ppm while firing natural gas, thereby eliminating the emission rate reduction slated for January 1, 2000. In order to ensure that the potential annual emissions (TPY) of NOx do not remain at the higher levels, further emission limits are proposed as described below. These emission limits will be accomplished by a reduction in the permitted operating hours of Unit 1 as well as an annual NOx cap for the combined operation of Units 1 and 2. No. Other emission limit increases are requested.

	Unit 1 potential NOx emissions	Unit 2 potential NOx emissions	Units 1 and 2 combined potential NOx emissions
As currently permitted	171.2	290.6	461.8
As permitted effective 1/1/00	116.9	290.6	407.5
As requested effective 1/1/00	103.5	290.6	366.1 (annual cap)

In addition to the above, a number of other Unit 1 pollutant emissions have the potential to be reduced. These are itemized below.

Pollutant - Tons per year (TPY)	Permitted Unit 1 Potential Emissions effective 1/1/00	Requested Unit 1 Potential Emissions effective 1/1/00	Unit 1 Potential Emissions Reductions
Particular Matter (PM/PM10)	40.9	24	16.9
Volatile Organic compounds (VOC)	6.9	4.3	2.6
Carbon Monoxide (CO)	193.2	121.5	71.7

It is noted that emissions from Unit 1 have ranged from 6 to 29 tons per year of NOx over a 5 year period. This reflects the peaking characteristics of the Unit. These values are less than significant for PSD and it is expected that the unit will typically operate in a similar manner in the future regardless of potential emissions.

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of "Public Notice of Intent to Issue PSD Permit Modification." Written comments should be provided to the Departments Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

Department of Environmental Protection
Central District Office
3319 Maguire Blvd., Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the Draft Permit modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 851/488-0114, for additional information.

P 265 659 306

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to A.K. Sharma	
Street & Number KUA	
Post Office, State, & ZIP Code Kissimmee Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 9-24-99 097D043-DO7-AC PSD-F1-182A	

PS Form **3800**, April 1995

Fold at line over top of envelope to the right of the return address

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
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I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. A.K. Sharma
Director of Power Supply
KUA
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

4a. Article Number
P 265 659 306

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
9-27-99

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X [signature]

8. Addressee's Address *(Only if requested and fee is paid)*

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

Thank you for using Return Receipt Service.

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED

SEP 30 1999

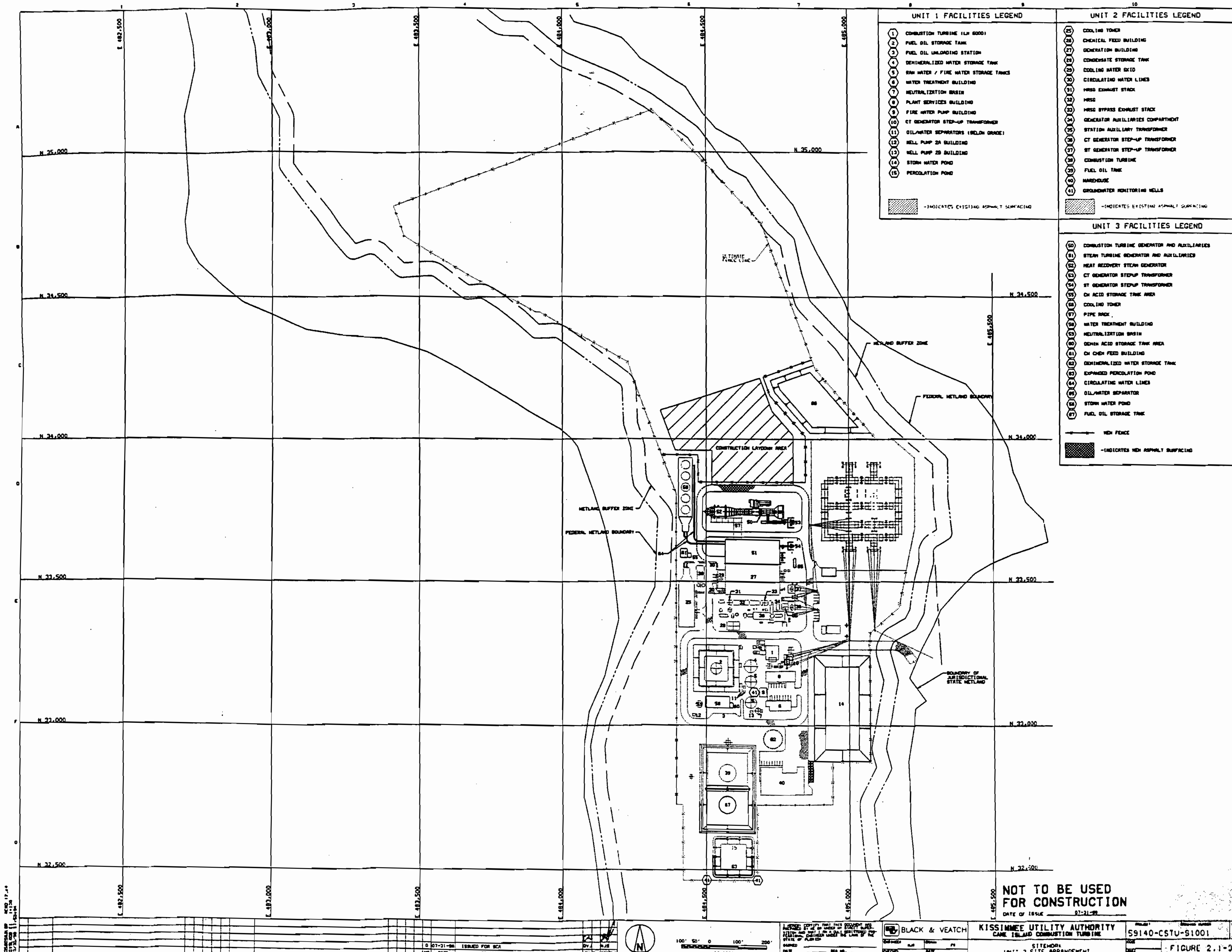
BUREAU OF AIR REGULATION

RECEIVED

SEP 30 1999

BUREAU C

Best Available Copy



STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

KUA (Halp...)
Unit 1 NOx Amendment
ELSA Forms 8/20/99
0970043-007-AC
PSD-FL-182

H

0970043-007-AC
PSD-FL-182a

KUA
Elsa

From

Site Cert.

Elsa

KUA

PSD-FI-254

To

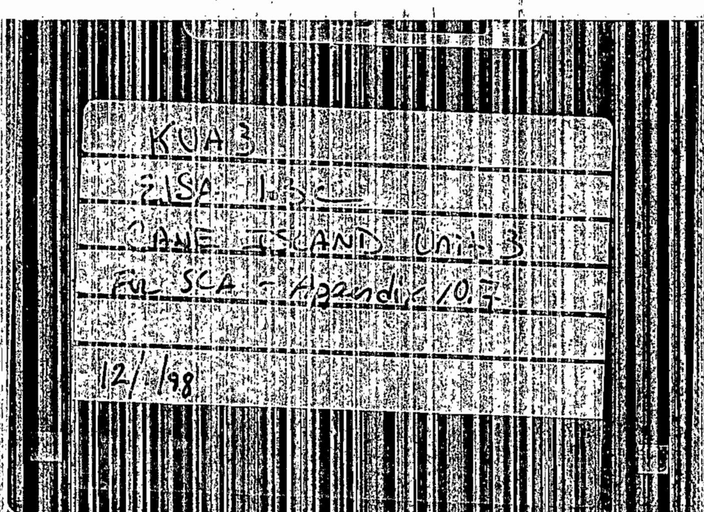
pa 98-38

DISK POCKET / MAILER

Handle With Care

FIRST CLASS MAIL

KUA PSD-FI-



STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

AIA

PSD-FL-254

PA 98-38

Cleve Doc

uploaded
12-3-04

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Print your name, address, and ZIP Code in this box •

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, NSRS
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

RECEIVED

DEC 27 1999

BUREAU OF AIR REGULATION

Z 031 391 907

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	K. K. Sharma
Street & Number	KUA
Post Office, State, & ZIP Code	Kissimmee Fl
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	0970043-007-AC PSD-FL-183A 12-20-99

PS Form **3800**, April 1995