BEST AVAILABLE COPY

Check Sheet

Company Name: Orange Cogeneration Limited Partnership
Permit Number: AC 53-233851, -233852
PSD Number: PSD FL-206
Permit Engineer:

Cross References:
- ☐
- ☐
- ☐

Application:
- ☐ Initial Application
- ☑ Incompleteness Letters 7/26/93
- ☑ Responses 8/8/93
- ☑ Waiver of Department Action
- ☐ Department Response
- ☐ Other

certified mail receipt is not present.

Intent:
- ☑ Intent to Issue
- ☑ Notice of Intent to Issue
- ☑ Technical Evaluation
- ☑ BACT or LAER Determination
- 2 ☑ Unsigned Permit
- Correspondence with:
  - ☐ EPA
  - ☐ Park Services
  - ☐ Other
- ☑ Proof of Publication
- ☐ Petitions - (Related to extensions, hearings, etc.)
- ☐ Waiver of Department Action
- ☐ Other

53-233852A
233851B
206A

Final Determination:
- ☑ Final Determination
- 2 ☑ Signed Permit
- ☑ BACT or LAER Determination
- ☐ Other

Post Permit Correspondence:
- ☑ Extensions/Amendments/Modifications
- ☑ Other

Revision #5

BEST AVAILABLE COPY

1/30/94

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

P 872 562 594

MAIL

RETURN TO SENDER

UNKNOWN

ATTEMPTED NOT KNOWN
NO SUCH NUMBER
VACANT
REFUSED
NO MAIL RECEPTACLE
TEMPORARILY AWAY

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration LP
3753 Howard Hughes Parkway, Suite 200
Las Vegas, NV 89109

BEST AVAILABLE COPY

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Willaam R. Malenius
3753 Howard Hughes Parkway, Suite 400
Las Vegas, NV 89109

4a. Article Number
P 872 562 594

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

7. Date of Delivery

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 DOMESTIC RETURN RECEIPT

Thank you for using Return Receipt Service.

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Kennard F. Kosky, P.E.
KBN Engineering and Applied Sciences
1034 Northwest 57th Street
Gainesville, Florida 32605

4a. Article Number
P 872 563 610

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

7. Date of Delivery
4-1-94

5. Signature (Addressee)
Mary Reinert

6. Signature (Agent)

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

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 563 610

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to	Mr. Kennard F. Kosky
Street and No.	1034 Northwest 57th Street
P.O., State and ZIP Code	Gainesville, FL 32605
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	Mailed: 3/30/94 AC 53-233851

PS Form **3800**, JUNE 1991

Best Available Copy

THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

State of Florida
County of Hillsborough } ss.

Before the undersigned authority personally appeared R. Putney, who on oath says that he is Accounting Manager of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE POLK

in the matter of

STATE OF FLORIDA

was published in said newspaper in the issues of

NOVEMBER 20, 1993

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

R Putney

Sworn to and subscribed before me, this 22ND *day of* NOVEMBER *, A.D. 19*93

Personally Known ✓ *or Produced Identification*

Type of Identification Produced

(SEAL)

Ina S Kennedy

INA S. KENNEDY
Notary Public, State of Florida
My comm. expires Mar. 22, 1996
No. CC187731

STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL
PROTECTION
NOTICE OF INTENT
TO ISSUE PERMITS

The Department of Environmental Protection gives notice of its intent to issue air pollution source construction permits (Permit Nos. AC 53-233851, AC 53-233852 and (PSD-FL-206)) to Orange Cogeneration Limited Partnership, 23046 Avenida De La Carlota, Suite 400, Laguna Hills, CA 92653. The proposed permits are for a natural gas/equivalent biogas fired 103 megawatt (MW), gross, cogeneration facility containing two combustion turbines, two heat recovery steam generators, and one 100 million British thermal unit per hour (MMBtu/hr), based on the high heating value (HHV) of the fuel, auxiliary boiler. The facility will be constructed near Orange-Co of Florida, Inc., on Clear Springs Road in Bartow, Polk County, Florida. Maximum facility emissions are estimated to be 11.6 tons per year (TPY) sulfur dioxide (SO2), 48.2 TPY particulate matter (PM), 393.8 TPY nitrogen oxides (NOX), 287.8 TPY carbon monoxide (CO), 53.7 TPY volatile organic compounds (VOC), and 0.89 TPY sulfuric acid mist.

The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations. The emission limits for PM, NOX, CO, and VOC are established by a Best Available Control Technology (BACT) determination. Modeling results show that increases in ground-level concentrations are less than Prevention of Significant Deterioration (PSD) significant impact levels for PM, NOX, and CO. These emissions will not cause or contribute to a violation of any ambient air quality standard or PSD increment. There are no ambiant air standards or increments for VOC. The Department's basis for this intent to issue are stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by this proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under section 120.57 Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and the telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of facts which petitioner contends warrants reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this notice, in the Office of General Counsel at the above address of the Department. Failure to petition within the allotted time frame constitutes a waiver of any rights such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application 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
Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination. Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

LK1313 11/20/93

INA S. KENNEDY
Notary Public, State of Florida
My comm. expires Mar. 22, 1996
No. CC187731

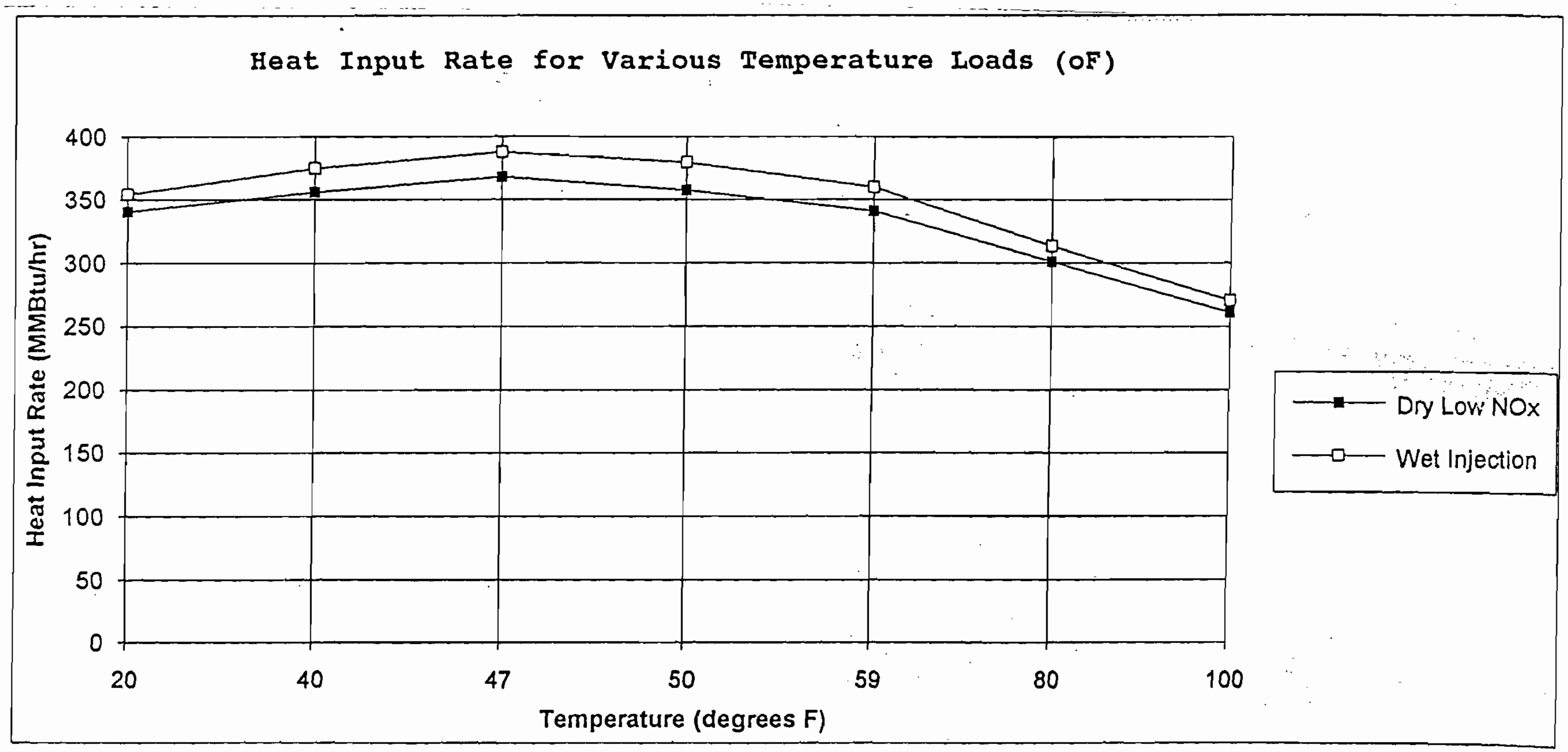
Michael L. Wilkinson, P.E.
Project Engineer

Central and South West Services, Inc.
1616 Woodall Rodgers Freeway
P.O. Box 660164 (214) 777-3718
Dallas, Texas 75266-0164 FAX (214) 777-1336

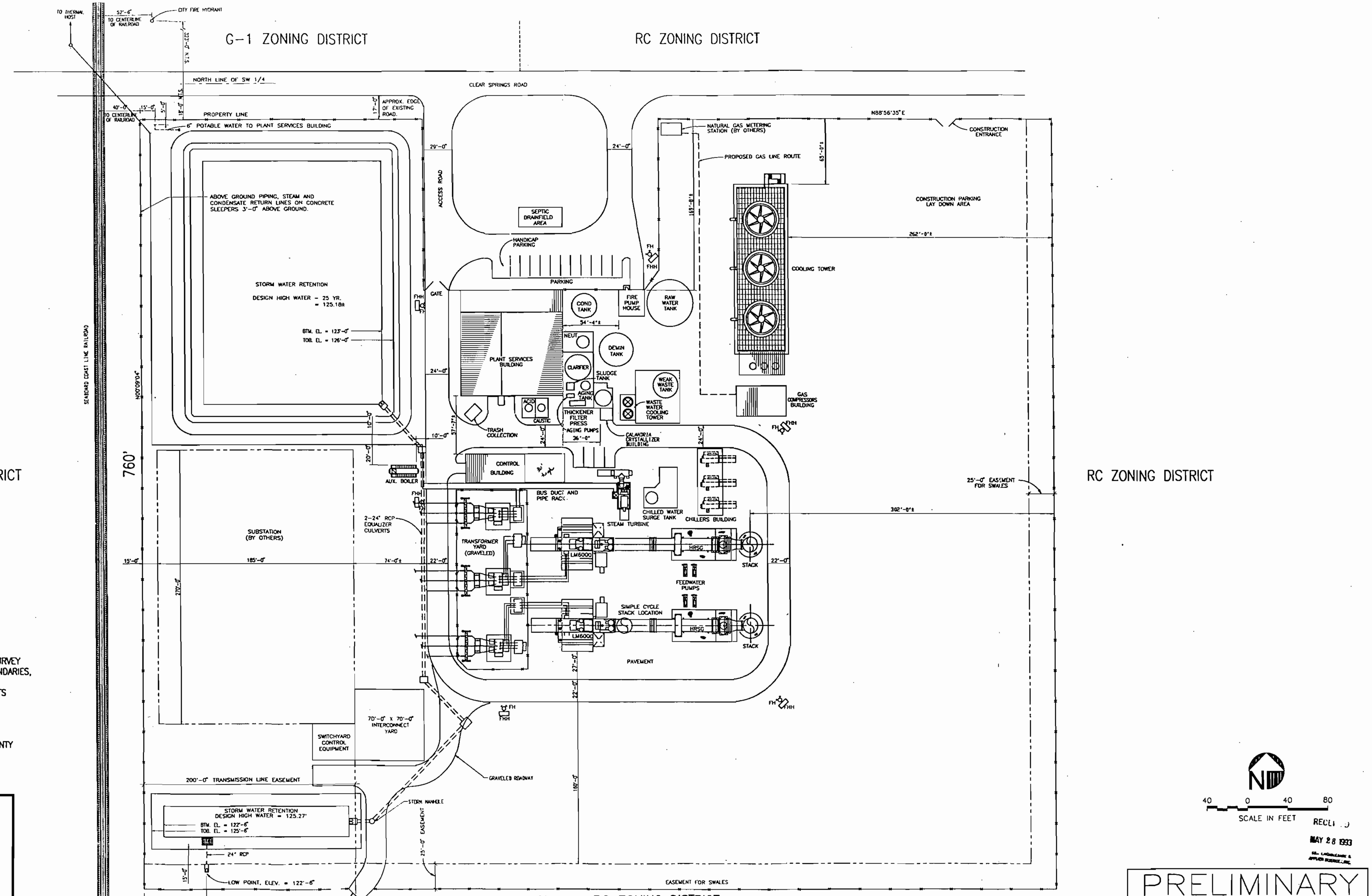
Davis G (Jeff) Reese
Manager, Legal & Public Affairs

23046 Avenida de la Carlota
Suite 400
Laguna Hills, California 92653
Telephone (714) 588-3767
Facsimile (714) 588-3972

ARK
ENERGY
INC.



ORANGECO.XLS Chart 1
10/27/93



NOTE:
1. ALL DIMENSIONS ARE APPROXIMATE, FINAL SURVEY WILL BE USED TO FIX SUCH ITEMS AS BOUNDARIES, BUILDING SPACING AND ROAD WIDTHS
2. FIRE PROTECTION SYSTEM INCLUDES HYDRANTS LOCATED AS SHOWN
   FH = FIRE HYDRANT
   FHH = FIRE HOSE HOUSE
3. POWER PLANT IS NATURAL GAS FIRED.
4. PROJECT SITE IS LOCATED WITHIN POLK COUNTY RC ZONING.
5. N.T.S. = NOT TO SCALE

Date:	5/17/93
Drawn By:	T. ALEXANDER
Checked By:	
Approved By:	

Figure 2-2 SITE LAYOUT

KBN

CSW Energy, Inc.
Operations
A Central and South West Company

Orange Cogen
1901 Clear Springs Road
P.O. Box 782
Bartow, FL 33831-0782
941-534-1141 • FAX 941-533-4152

AL

clair / Al

Certified Mail
Return Receipt Requested

April 9, 1998

Howard L. Rhodes, Director
Division of Air Resources Management
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Permit Modification No. 105023-1-002-AC, PSD-FL-206B
Bartow Facility, Extension of NO_x Compliance Date

Dear Mr. Rhodes:

Pursuant to Specific Condition 19 of your correspondence dated August 25, 1997 regarding the above-referenced permit, enclosed is a copy of the Quarterly Status Report for the first quarter of 1998 - Orange Cogen 15 ppm Nox Emissions, submitted by General Electric.

If you have any questions, please feel free to contact me.

Sincerely,

Don Walters

Don Walters
Operations & Maintenance Manager

WS/kc
enclosure
cc: Joe Cox, DEP, Tampa
Dennis Oehring
Wade Smith
cc: M. Costello

March 17, 1998 CM- MI98-12673

Quarterly Status Report - Orange Cogen 15ppm NOx Emissions

Background

Two LM6000 PB engines (ESN 190206 and 190207) are installed at Orange Cogeneration in Bartow, Florida. These engines are equipped with a dry low emissions (DLE) combustion system. As of December 1997 these engines have accumulated approximately 12,000 hours of operation each.

The original contract for these engines specified NOx emissions to be 15 parts per million (ppm) by January 1, 1998. When the engines were first installed NOx levels were approximately 18 ppm, hence GE Marine & Industrial Engines started a program to improve NOx. As a part of this program several tests have been conducted on the Orange engines during the past 3 years. These tests identified emissions improvements however other changes were also needed to improve acoustics and durability. As a result, the schedule to complete this program has slipped from December 1997 to December 1998. Because of this slip, and based on the progress to date, CSW and GE petitioned the Florida Department of Environmental Protection to extend the required date for 15ppm from January 1998 to January 1999. This extension has recently been approved. The purpose of this report is to provide the status of this program as of March 1998.

Program Status

The technical approach of increasing airflow to the combustor premixers has been further explored. Emissions data was collected from two LM6000PB engines, ESN 190206 and ESN 190207, to determine the practical boundaries of both NOx and CO. The data was obtained by adjusting the nominal control schedule to minimize NOx at several power settings and firing temperatures. The data is plotted as CO versus NOx in Figure 1. The LM6000PB data reveal that as NOx is reduced below 15ppm, rapid increases in CO will be experienced. Current LM6000 experience shows that the control schedule must be adjusted to a nominal CO level of 10ppm or below in order to maintain CO levels within compliance and prevent operability problems during day to day operation. Therefore, this data indicates that 14ppm is the minimum practical NOx achievable on these LM6000 PB engines. Based upon previously obtained data, this level would only be achievable with a restored engine with increased flow premixers. Engine deterioration studies were conducted for this

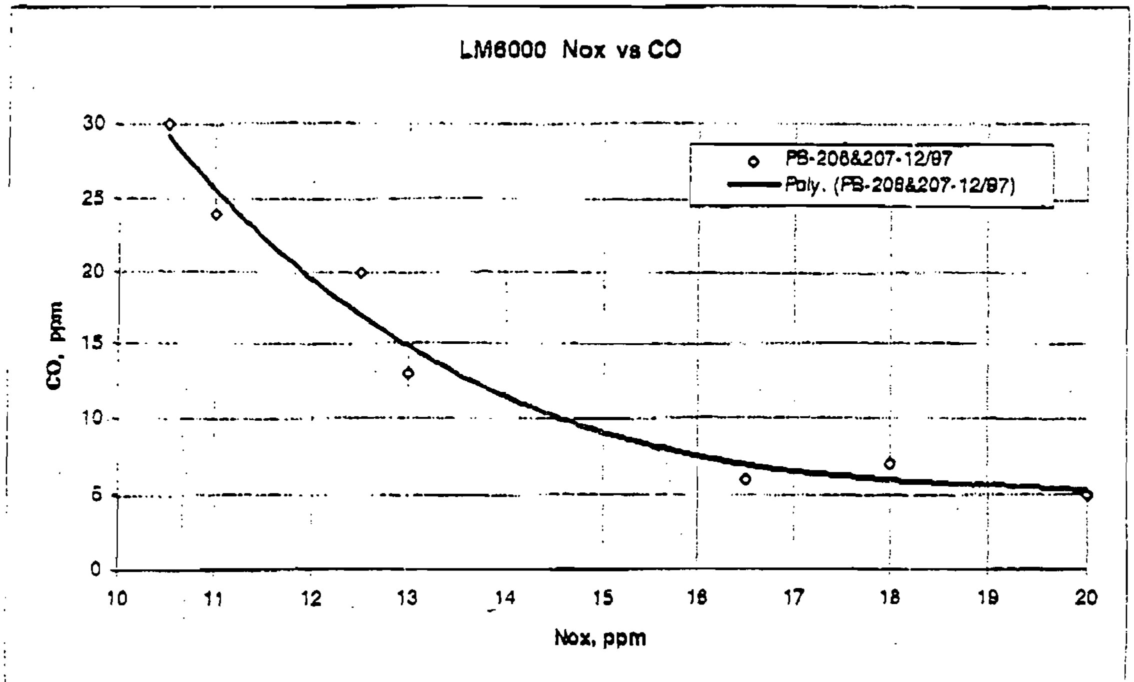


Figure 1. LM6000PB /PD Emissions Characteristics

configuration which indicate that this engine would require considerable maintenance in the form of performance restoration to maintain 15ppm NOx levels.

Additional data was obtained at the GE factory on three LM6000PD engines, ESN 192-105, 192-110, 192-111, for comparison to the LM6000PB data. The LM6000PD engine contains booster and low pressure turbine performance and durability improvements relative to the LM6000PB engine. These improvements increase combustor airflow and decrease fuel consumption to allow a leaner fuel/air mixture relative to the LM6000PB engine. Based upon engine cycle studies, a NOx improvement greater than 4ppm NOx is expected. The data confirm the expected decrease in NOx level with demonstrated levels of 12-14ppm at 41.4MW. For comparison, the LM6000PB engines first installed at CSW produced NOx levels of approximately 18 ppm. This data also showed the LM6000PD CO levels are considerably lower than the LM6000PB at the same NOx level. This was unexpected since the identical combustor is used in both engines. Since the LM6000PD data was obtained on new engines, this difference in emissions characteristics may be the result of combustor deterioration in the form of heatsheild cooling air leakage and/or premixer gas flow maldistribution. The data also indicate that further NOx reductions may be possible using the increased airflow premixers demonstrated on ESN 190206, however, further engine testing is required to determine the emissions characteristics with this configuration. Based upon the availability of a set of increased airflow premixers and LM6000PD factory test schedules, this test would most likely not occur until the 4th quarter of 1998.

Next Steps:

Based upon the information gathered to date, implementation of a practical 15ppm NOx technology will not be obtainable with the current LM6000PB platform without significant combustor development. Two additional approaches have been identified, LM6000PD and LM6000PC with steam injection, but will require further study and engine testing to determine practicality.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT MODIFICATION

In the Matter of an
Application for Permit Modification by

Mr. Allan Wade Smith, General Manager
Orange Cogeneration L.P., Inc.
1125 US Highway 98 South, Suite 100
Lakeland, Florida 33801

DEP File No. 1050231-002-AC
PSD-FL-206B
Polk County

Enclosed is Permit Modification Number 1050231-002-AC (PSD-FL-206B) extending the date of compliance with the nitrogen oxide emission limit at Orange Cogeneration's combined cycle unit located in Bartow, Polk County. This permit modification is issued pursuant to Chapter 403, Florida Statutes.

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

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 NOTICE OF FINAL PERMIT MODIFICATION (including the FINAL permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8-25-97 to the person(s) listed:

Mr. Allan Wade Smith, Orange Cogen L.P. *
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Bill Thomas, SWD
Mr. Roy Harwood, Polk County

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Tober 8-25-97
(Clerk) (Date)

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

August 25, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Allan Wade Smith
General Manager
Orange Cogeneration L.P., Inc.
1125 US Highway 98 South, Suite 100
Lakeland, Florida 33801

Re: Permit Modification No. 1050231-002-AC, PSD-FL-206B
Bartow Facility, Extension of NO_X Compliance Date

Dear Mr. Smith:

The Department has reviewed the modification requested in your letter dated June 6, 1997. The referenced permit is hereby modified as follows:

SPECIFIC CONDITION 10

Prior to January 1, ~~1998~~ 1999, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit, shall not exceed 25 parts per million by volume dry corrected to 15 percent oxygen (25 ppmvd @ 15% O_2), as determined by the procedures in Specific Conditions Nos. 16, 17 and 18.

SPECIFIC CONDITION 11

After December 31, ~~1997~~ 1998, the maximum NO_x concentration, 1-hour average, from each CT/HSRG unit, shall not exceed 15 ppmvd @ 15% O_2, as determined by the procedures in Specific Conditions Nos. 16, 17 and 18. ~~Should the NO_x standard of 15 ppmvd @ 15% O_2 not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard.~~ The permittee shall obtain prior approval from the Department for any air pollution control equipment not addressed in this permit that is needed to meet the NO_x emission standard.

SPECIFIC CONDITION 15

Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review by January 1, ~~1998~~ 1999. Until new curves are approved by the Department or the combustion turbines meet the NOx emission standard of 15 ppmvd @ 15% (whichever occurs first), the stack, operator, and emission data for the proposed combustion turbines in Table 2-4 (October 28, 1993) will be used. The data will be used to determine compliance with the maximum allowable emission rates of the regulated air pollutants at different air inlet temperatures for these turbines.

SPECIFIC CONDITION 16

Testing of emissions shall be conducted at 95-100% of the manufacturer's rated heat input based on the average air inlet temperature for the CT during the test. Compliance for NO_x emission limits shall be determined by calculating the concentration of NO_x (ppmvd at 15% O_2) and using the turbine manufacturer's thermal throughput rating for the average air inlet temperature by multiplying the permitted emission limit by the ratio of the tested heat input to the maximum heat input (MMBtu/hr) at this temperature. Compliance with the visible emissions, NO_x, SO_2, CO, PM/PM_{10}, and VOC emission standards shall be determined annually thereafter. Tests shall be conducted on both natural gas and biogas fuels, provided biogas gas fuels become available. If the initial tests or fuel analyses show the emissions of air pollutants from the combustion turbines are independent of the fuel (natural gas or biogas fuel), then annual compliance tests can be conducted while the combustion turbines are burning either fuel.

SPECIFIC CONDITION 19

Prior to January 1, 1998, the permittee shall provide a report showing how the allowable NO_x emissions of 15 ppmvd @ 15% O_2 is achieved by the CT's. The permittee shall provide quarterly reports regarding the progress toward attaining the allowable NO_x emissions of 15 ppmvd @ 15% O_2 until such emission level is attained.

TABLE 1

The compliance date is hereby changed to 1/1/99 as is the date in Note (d).

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/mc

P:/nsrs/costello/orange/ormodltr.doc

Memorandum

Florida Department of Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy aaf for CHF 8/20

THRU: Al Linero aaf 8/20

FROM: Marty Costello MC

DATE: August 20, 1997

SUBJECT: Orange Cogeneration Permit Modification No. 1050231-002-AC, PSD-FL-206B

Attached is a letter modifying a construction permit for the Orange Cogen Bartow Facility to allow an additional year for the demonstration of a consistent level of NO_x at 15 ppmvd @ 15% O_2 from this General Electric dry low-NOx technology on the two LM6000 combined cycle units.

In addition, this action provides clarification of Specific Condition 16 that tests shall be conducted on both natural gas and biogas fuels, provided biogas fuels become available.

No adverse comments were received from the public notice which was published on July 10.

I recommend your approval and signature.

P 265 659 444

no green card

US Postal Service

Receipt for Certified Mail 7/98

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Allan W Smith	
Street & Number Cosen	
Post Office, State, & ZIP Code Orange	
Postage Lakeland, Fl	$
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 1050231-002-AC 8-25-97	

PS Form 3800, April 1995

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF REVISED PERMITS

In the matter of an
Application for Revised Permits by:

DEP File Nos. AC 53-233852A
AC 53-233851B
PSD-FL-206A&B
Polk County

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration Limited Partnership
23046 Avendia De La Carlota
Laguna Hills, CA 92653

Enclosed are revised permits, Nos. AC 53-233852A & AC 53-233851B and PSD-FL-206B, and the revised Best Available Control Technology (BACT) determination for two gas combustion turbines and one auxiliary boiler to be located in Bartow, Polk County, Florida. These revised permits and BACT determination change the nitrogen oxides emission standard concentration from 15 parts per million by volume dry corrected to 15 percent oxygen and ISO ambient standard conditions (15 ppmvd @ 15% O_2 @ ISO) to the observed concentration of 15 ppmvd @ 15% O_2. These revised permits and BACT determination are issued pursuant to Section 403, Florida Statutes.

Any party to this Order (revised permits) has the right to seek judicial review of the revised permits pursuant to Section 120.68, Florida Statutes, by filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF REVISED PERMITS and all copies were mailed by certified mail before the close of business on 3-7-95 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk 3-7-95
Date

Copies furnished to:

B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
L. Novak, PCESD
K. Kosky, P.E., KBN
T. Donovan, OCLP

FINAL DETERMINATION

Orange Cogeneration L.P.

AC 53-233852A & AC 53-233851B
PSD-FL-206B

An Intent to Issue Revised Permits for Orange Cogeneration Limited Partnership proposed combustion turbines and auxiliary boiler to be located in Bartow, Polk County, Florida, was distributed on December 29, 1994. The Notice of Intent to Issue Revised Permits was published in the Polk County Democrat on January 5, 1995.

Orange Cogeneration Limited Partnership submitted a comment in a letter dated January 26, 1995. It was noted that the nitrogen oxides emission standard in Specific Condition No. 19 had the ISO condition listed and not been revised, which was the purpose of the request. The Department agrees with this comment and has corrected the condition.

The final action of the Department will be to issue the revised permits and BACT as proposed in the Intent to Issue Revised Permits, except for the change noted above.

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233851B
PSD-FL-206B
Expiration Date: April 1, 1998
County: Polk
Latitude/Longitude: 27°52'15"N
81°49'31"W
Project: Two Combustion Turbines

This revised permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of two natural gas/biogas fired GE LM 6000 (or equivalent) combustion turbines (CT), two heat recovery steam generators and one steam turbine. An auxiliary boiler (AC53-233852) is being permitted separately. The CTs will be equipped with **a staged combustion technology** dry low-NO_X system to control nitrogen oxides (NO_X) emissions. Each CT will be equipped with a 100 ft. high, 11 ft. diameter stack that will handle approximately 300,000 actual cubic feet per minute of flue gas at 230°F. The cogeneration facility will be located on Clear Springs Road, Bartow, Polk County, Florida.

The UTM coordinates of this facility are Zone 17, 418.75 km East and 3083.0 km North.

The emissions unit(s)/sources shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below:</u>

1. Application received July 1, 1993.
2. Department's July 22, 1993 letter.
3. KBN's August 5, 1993 letter.
4. KBN's August 29, 1993 letter.
5. Tables 1 and 2, Allowable Emission Rates.
6. KBN's October 28, 1993 letter.
7. KBN's October 29, 1993 letter.
8. Department's February 18, 1994 letter.
9. KBN's March 11, 1994 letter.
10. Department's March 29, 1994 letter.
11. KBN's June 22, 1994 letter.
12. KBN's October 10, 1994 letter.

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. a description of and cause of non-compliance; and,

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

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

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

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

GENERAL CONDITIONS:

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

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

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

    - the date, exact place, and time of sampling or measurements;
    - the person responsible for performing the sampling or measurements;
    - the dates analyses were performed;
    - the person responsible for performing the analyses;
    - the analytical techniques or methods used; and,
    - the results of such analyses.

GENERAL CONDITIONS:

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

SPECIFIC CONDITIONS:

This permit replaces permit No. AC53-233851/PSD-FL-206 and amended construction permit No. AC53-233851A/PSD-FL-206A.

Construction Requirements

1. Dry low-NO_X **combustion technology** systems shall be installed and operated on each combustion turbine (CT).

2. A system to continuously monitor the fuel consumption, nitrogen oxides emissions, and oxygen content of the flue gas shall be installed on each CT.

3. The heat recovery steam generator (HRSG) installed on each CT shall not be equipped with an auxiliary/duct burner.

4. Each CT stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, and electrical power) that meet the specifications given in Rule 62-297.345, F.A.C.

Operation Limitations

5. The CTs shall comply with all requirements of 40 CFR 60, Subpart GG (July, 1993), Standard of Performance for Stationary Gas Turbines, which is adopted by reference in Rule 62-296.800(2)(a), F.A.C.

6. The facility is allowed to operate continuously, 8760 hours per year.

7. Only natural gas/biogas fuel shall be used for fuel at this facility.

8. Each CT shall have a maximum heat input of 368.3 MMBtu/hr, when using dry low NO_X technology to control NO_X emissions.

9. The operation of this facility shall not create a nuisance or discharge air pollutants that cause or contribute to objectionable odors **pursuant to Rule 62-296.320(2), F.A.C.**

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851B (PSD-FL-206B)
42 MW COMBINED CYCLE GAS TURBINES

Table 1 - Allowable Emission Rates[b] for each Combustion Turbine

		Allowable Emissions Standards/Limitations				
Pollutant[a]	Control[e]	Concentration	Compl. Date	Maximum Corrected[c] lbs/hr	TPY	Basis for Limit
NO_x	DLN	25 ppmvd at 15% O_2[d]	initial	37.0	161.9	BACT
	DLN	15 ppmvd at 15% O_2[d]	1/1/98	22.1	97.0	BACT
CO	GC[f]	30 ppmvd		27.8	127.0	BACT
PM/PM_{10}	GC[f]			5	21.9	BACT
VOC	GC[f]	10 ppmvd		3.98	17.4	BACT

[a] Pollutant emissions are based on 8,760 hours per year operation firing natural gas or biogas.

[b] Allowable emissions, lbs/hr, at different inlet temperatures shall not exceed the rates given in the manufacturer's data required by specific condition No. 15.

[c] Maximum emission rates not to be exceeded.

[d] The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the initial compliance demonstration stack tests are performed, the permittee must provide the Department with a plan and schedule to meet this standard. NO_x emission concentrations are to be corrected to 15 percent oxygen to demonstrate compliance with the NO_x emissions standard.

[e] Dry Low-NO_x (DLN) combustors.

[f] Good Combustion.

SPECIFIC CONDITIONS:

Emission Limitation

10. Prior to January 1, 1998, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit, shall not exceed 25 parts per million by volume dry corrected to 15 percent oxygen (25 ppmvd @ 15% O_2), as determined by the procedures in Specific Conditions Nos. 16, 17 and 18.

11. After December 31, 1997, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit, shall not exceed 15 ppmvd @ 15% O_2, as determined by the procedures in Specific Conditions Nos. 16, 17 and 18. Should the NO_x standard of 15 ppmvd @ 15% O_2 not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard. The permittee shall obtain prior approval from the Department for any air pollution control equipment not addressed in this permit that is needed to meet the NO_x emission standard.

12. The maximum emission rates for particulate matter (PM/PM_{10}), volatile organic compounds (VOC), NO_x, and carbon monoxide (CO) shall not exceed any of the rates listed in Table 1, Allowable Emission Rates.

13. Visible emissions shall not exceed 10 percent opacity, 6 minute average.

14. The emission rates for sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist, listed in the following table, shall be used for inventory purposes only.

Maximum Emission Rates for Each Combustion Turbine
For Inventory and PSD Tracking Purposes Only

Pollutant	Combustion Turbine Dry Low NO_x Combustion lb/hr	TPY
SO_2	1.11	4.87
H_2SO_4 mist	0.085	0.37

15. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review **by January 1, 1998.** Until new curves are approved by the Department or the combustion turbines meet the NO_x emission standard of 15 ppmvd @ 15% (whichever occurs first), the stack, operator, and emission data for the proposed combustion turbines in

SPECIFIC CONDITIONS:

Table 2-4 **(October 28, 1993)** will be used. The data will be used to determine compliance with the maximum allowable emission rates of the regulated air pollutants at different air inlet temperatures for these turbines.

Compliance Determination

16. Testing of emissions shall be conducted at **95-100%** of the manufacturer's rated heat input based on the **average air inlet temperature** for the CT during the test. **Compliance for NO_x emission limits shall be determined by calculating the concentration of NO_x (ppmvd at 15% O_2) and using the turbine manufacturer's thermal throughput rating for the average air inlet temperature by multiplying the permitted emission limit by the ratio of the tested heat input to the maximum heat input (MMBtu/hr) at this temperature.** Compliance with the visible emissions, NO_x, SO_2, CO, PM/PM_{10}, and VOC emission standards shall be determined within 60 days of achieving maximum production but not later than 180 days after initial firing of each CT (40 CFR 60.8). Compliance with the visible emissions **limitation and the** NO_x and SO_2 **emission** standards shall be determined annually thereafter. **Tests shall be conducted on both natural gas and biogas fuels. If the initial tests or fuel analyses show the emissions of air pollutants from the combustion turbines are independent of the fuel (natural gas or biogas fuel), then annual compliance tests can be conducted while the combustion turbines are burning either fuel.**

17. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

Pollutant	EPA Method
PM/PM_{10}*	5 or 17**
NO_x	20
CO	10
VOC	18 or 25A
Visible Emissions	9

NOTE: No other test methods may be used for compliance testing **unless** prior Department **written** approval **has been received.**
* **Assumption is that all PM is PM_{10}.**
** Stack flue gas temperature must be less than 320°F to use Method 17.

SPECIFIC CONDITIONS:

Monitoring

18. **NO_x and oxygen monitoring to meet the requirements of 40 CFR 60, Subpart GG, shall be accomplished using a continuous emission monitoring (CEM) system. The CEM system shall meet the requirements of 40 CFR 60, Appendix B. The requirements of 40 CFR 75, Appendices A and B, can be substituted for those of 40 CFR 60 provided the minimum criteria of 40 CFR 60 are met. NO_x monitoring to indicate compliance with the BACT limit shall be based on one hour average emissions determined on ppmvd @ 15% O_2.**

Administrative Requirement

19. Prior to January 1, 1998, the permittee shall provide a report showing how the allowable NO_x emissions of 15 ppmvd @ 15% O_2 is achieved by the CTs.

20. The permittee shall provide the Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction
- Anticipated date of initial starting 30 to 60 days prior to startup
- Actual date of startup up within 15 days after the starting
- Notification of the date of the compliance tests not less than 30 days prior to the test

21. Pursuant to Rule 62-210.370(2), F.A.C., Air Operating **Reports**, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, and air emissions. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

22. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the **Department's** Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

23. An application for an operation permit must be submitted to the **Department's** Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the

SPECIFIC CONDITIONS:

construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Daniel H Thomas For

Virginia B. Wetherell, Secretary

Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233852A
PSD-FL-206B
Expiration Date: April 1, 1996
Latitude/Longitude: 27°52'15"N 81°49'31"W
Project: Auxiliary Boiler
County: Polk

This revised permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of a 100 million British thermal unit per hour (MMBtu/hr) natural gas/equivalent biogas fired tube boiler equipped with a 65 foot high, 3.67 foot diameter stack designed to produce approximately 83,000 pounds per hour of saturated steam at 205 pounds per square inch gauge (psig) pressure. The heat input is based on the High Heating Value (HHV) of the fuel. The auxiliary boiler will be located on Clear Springs Road, Bartow, Polk County, Florida 33830.

The UTM coordinates of this facility are Zone 17, 418.75 kmE and 3083.0 kmN.

The emission unit/source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. Application received July 1, 1993.
2. Department's July 22, 1993 letter.
3. KBN's August 5, 1993 letter.

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. A description of and cause of non-compliance; and,

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

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

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

GENERAL CONDITIONS:

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

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

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

13. This permit also constitutes:

    (X) Determination of Best Available Control Technology (BACT)
    (X) Determination of Prevention of Significant Deterioration (PSD)
    (X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and,
- the results of such analyses.

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

SPECIFIC CONDITIONS:

Construction Requirements

1. The auxiliary boiler shall be equipped with low-NO_X burners.

2. The boiler stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, electrical power) that meet the specifications given in Rule 62-297.345, F.A.C.

Operation Limitations

3. The auxiliary boiler shall comply with all applicable requirements of 40 CFR 60, Subpart Dc.

4. The boiler is allowed to operate continuously, 8760 hours per year.

5. Only natural gas/equivalent biogas fuel shall be burned in this boiler.

6. The maximum heat input to the boiler, **which is** based on the high heating value (HHV) of the fuel, shall not exceed 100 MMBtu/hr.

7. The maximum allowable sulfur content (total) of the natural gas/biogas burned in the boiler shall not exceed 1 grain per 100 cubic feet (1 gr/100 CF) of gas.

PERMITTEE:
Orange Cogeneration Limited Partnership

Permit Number: AC53-233852A
Expiration Date: April 1, 1996

SPECIFIC CONDITIONS:

8. The operation of this boiler shall not emit air pollutants that cause or contribute to objectionable odors.

9. Visible emissions shall not exceed 15 percent opacity.

10. Emissions from the boiler shall not exceed any of the following limits:

Pollutant	lb/MMBtu	lbs/hr	TPY
NO_x	0.13	13.0	56.9
CO	0.10	10.0	43.8
VOC	0.04	4.3	18.8

11. Sulfur dioxide ~~(SO_2)~~ emissions from the boiler shall not exceed 0.003 lb/MMBtu, 0.30 lb/hr, and 1.3 TPY. An analysis of the fuel showing the sulfur content does not exceed 1 grain of total sulfur per 100 cubic feet of gas will be accepted as proof of compliance with the sulfur dioxide emission limit. Total sulfur content of the gas shall be determined by test method ASTM D 1072-80 (40 CFR 60.17 (July, 1993)).

12. Particulate matter ~~(PM/PM_{10})~~ emissions from the boiler shall not exceed 0.01 lb/MMBtu, 1.0 lb/hr, and 4.4 TPY. No PM/PM_{10} stack test is required if the ~~visible~~ emissions **limitation is** less than 15 percent opacity.

Testing Requirements

13. Testing of emissions shall be conducted with the source operating at **permitted** capacity. Capacity is defined as 90-100% of **the maximum operating rate allowed by the permit.** If it is impracticable to test at **permitted** capacity, then sources may be tested at less than **90% of the maximum operating rate allowed by the permit.** In this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Compliance with the visible emissions **limitation and the** NO_x, CO, and VOC emission standards shall be determined within 60 days of achieving maximum production, but not later than 180 days after initial firing of the boiler. Compliance with the visible emissions **limitation** and **the** NO_x **emission** standards shall be determined annually thereafter.

SPECIFIC CONDITIONS:

14. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

Pollutant	EPA Method
PM/PM_{10}*	5 or 17**
NO_x	7E
CO	10
VOC	18 or 25A
Visible Emissions	9

NOTE: No other test methods may be used for compliance testing **unless** prior Department **written** approval **has been received.**
*** Assumption is that all PM is PM_{10}.**
**** Stack flue gas temperature must be less than 320°F for Method 17.**

15. The permittee shall provide the Department's Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction.
- Anticipated date of initial startup, 30 to 60 days prior to startup.
- Actual date of startup within 15 days after the startup.
- Notification of the date of the compliance tests not less than 30 days prior to the tests.

16. Pursuant to Rule 62-210.370(2), F.A.C., Air Operating **Reports**, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emission limits, etc. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

17. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

18. An application for an operation permit must be submitted to the Department's Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the

SPECIFIC CONDITIONS:

appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary

Revised Best Available Control Technology (BACT) Determination
Orange Cogeneration Limited Partnership
Polk County
AC53-233852A and AC53-233851B (PSD-FL-206B)

The applicant proposes to construct a 103 gross megawatt (MW) natural gas/biogas fired cogeneration facility in Bartow, Polk County, Florida. Major components of the cogeneration facility are: two combustion turbines (CT), each with a heat recovery steam generator (HRSG), an auxiliary boiler, steam turbine generator, and associated equipment. Both CTs will consume up to 776 million British thermal units per hour (MMBtu/hr) of gas fuel based on the lower heating value (LHV) of the fuel and produce 78 MW of electricity. The HRSGs, which do not use supplemental fuel, produce approximately 100,000 lbs/hr of steam and generate 25 MW of electricity. The fire-tube auxiliary boiler will consume 100 MMBtu/hr of gaseous fuel and produce approximately 83,000 lbs/hr of steam.

The following table lists the estimated maximum emissions from the cogeneration facility.

	Two CTs		Auxiliary Boiler	
Pollutant	lbs/hr	TPY	lbs/hr	TPY
Sulfur dioxide (SO_2)	2.34	10.3	0.3	1.3
Particulate Matter (PM/PM_{10})	10	43.8	1.0	4.4
Nitrogen Oxide (NO_x)	77.0	336.9	13.0	56.9
Carbon Monoxide (CO)	55.6	243.9	10.0	43.8
Volatile Organic Compounds (VOC)	7.96	34.9	4.3	18.8
Sulfuric Acid Mist	0.18	0.79	0.023	0.1

The cogeneration facility requires a BACT determination for NO_x, CO, PM, and VOC. In addition, the auxiliary boiler requires a BACT determination for **PM and** SO_2.

Date of Receipt of a BACT Application

July 1, 1993

BACT Requested by the Applicant

Pollutant	Proposed Limit	Air Pollution Control
Combustion Turbine		
PM	0.01 gr/scf*	Clean Fuel (gas) and
NO_x	25 ppmvd @ 15%**	Dry Low-NOx Combustors
	15 ppmvd @ 15%**	

CO	30 ppmvd	Combustion Controls
VOC	10 ppmvd	Combustion Controls

Auxiliary Boiler

PM	0.01 lbs/MMBtu	Clean Fuel (gas)
NO_x	0.13 lbs/MMBtu	Low-NO_x burners
SO_2	1 grain/100 CF natural gas	Clean Fuel (natural gas)
CO	0.10 lbs/MMBtu	Combustion Control
VOC	0.043 lbs/MMBtu	Combustion Control

*grains per standard cubic foot
**parts per million by volume dry at 15 percent oxygen
Applicant is committed to meeting 15 ppmvd @ 15% O_2 with dry low-NO_x combustors after December 31, 1997.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 62-212, 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, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from cogeneration facilities 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:

- Combustion Products (e.g., particulates matter). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.
- Acid Gases (e.g., NO_X). Controlled generally by gaseous control devices.

Although all of the pollutants addressed in the BACT analysis may be subjected 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, 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.

<u>BACT Pollutant Analysis for the Combustion Turbines (CTs)</u>

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 control technologies evaluated were selective catalytic reduction (SCR), wet injection (WI), dry low-NO_X combustor, NO_XOUT process, thermal DeNO_X, and selective noncatalytic reduction (SNCR).

NO_XOUT (urea with catalyst), thermal DeNO_X (ammonia with catalyst), and selective noncatalytic reduction system (ammonia without catalyst) to reduce NO_X emissions from the CT were not feasible because of process constraints (flue gas temperature too low and oxygen content too high).

SCR, dry low-NO_X combustor technology, and wet injection controls were considered feasible.

The applicant has stated that BACT for nitrogen oxides will be met by using advanced combustor design to limit emissions to 25 ppmvd @ 15% O_2, when burning natural gas/biogas. After December 31, 1997, a limit of 15 ppmvd @ 15% O_2 will be met. Should 15 ppmvd NO_x @ 15% O_2 not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard.

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 SCR system.

SCR 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 though the catalyst bed. With a new catalyst, the SCR process can achieve up to 90% reduction of NO_x. As the catalyst ages, the maximum NO_x reduction will decrease.

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°F.

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.

Although technically feasible, the applicant has 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 (spent 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) The energy impacts of SCR will reduce potential electrical power generation by 0.8 percent.

f) Incremental cost effectiveness for the application of SCR technology to the Orange Cogeneration L.P. project was considered to be $7,970 when emissions are at 25 ppm and $23,510 when emissions are at 15 ppm. Since SCR has been determined to be BACT for gas turbines, 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 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."

The cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR.

A concern associated with the use of SCR on combustion turbines 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 in some previous BACT determinations. This salt also increases particulate matter (PM/PM_{10}) emissions.

For natural gas/equivalent biogas 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. 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 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 on two CTs for this project at 100 percent capacity factor and burning natural gas/equivalent biogas is $1,648,000. A SCR would reduce the NO_x emissions by 207 TPY during the first 2 years of operation when the CTs emit 25 ppmvd @ 15% O_2. Thereafter, when dry-low NO_x controls are used, a SCR would reduce NO_x emissions by 120 TPY. When these reductions are taken into consideration, the total cost with SCR is $21,900 per ton of NO_X removed. This calculated cost is higher than has previously been approved as BACT.

A review of the latest Department BACT determinations show limits of 15 ppmvd (natural gas) using **dry** low-NO_X **combustor** technology for gas turbines. Most combustion turbine manufacturers are currently developing programs using both steam/water injection and dry low-NO_X combustor **technology** to achieve **a** NO_X emission control level of 9 ppm when firing natural gas. Therefore, this technology will likely be available by 1998.

BACT Determination for NO_X for the CTs by the Department

NO_X Control

The information that the applicant presented and Department calculation indicate that the cost per ton of controlling NO_X for this turbine [$21,900 per ton] 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 combustion turbine 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/steam injection and **dry** low-NO_X **combustor technology** design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that combustion turbine manufacturers are developing programs 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.

Based on this, the Department has determined to revise and lower the allowable BACT limit for this project to 15 ppmvd at 15% O_2 **and is to be achieved** no later than 1/1/98.

Carbon Monoxide (CO)

CO emissions are caused by incomplete combustion of the fossil fuel. The applicant investigated the use of combustion control and catalytic oxidation to control CO emission. With combustion control, CO emissions would be 30 ppmvd (236 TPY). With catalytic oxidation, CO emissions would be 10 ppmvd (78 TPY). The annualized cost of the catalyst system is $834,700 or $5,280 per ton of CO removed.

BACT Determination for CO for the CTs by the Department

Because catalytic oxidation would increase operation cost by $5,280 per ton of CO removed, and have no significant reduction in ambient air quality, the Department accepts an emission limit for CO of 30 ppmvd obtained through combustion control as BACT for these CTs.

Volatile Organic Compounds (VOC)

VOC emissions are caused by incomplete combustion of fossil fuel. The applicant proposes to meet an emission limit of 10 ppmvd through the use of clean fuel (natural gas) and combustion controls. This is similar to the BACT applied to other **similar** sources.

BACT Determinations for VOC for the CTs by the Department

The Department accepts an emission limit for VOC of 10 ppmvd obtained through the use of clean fuel (natural gas) and combustion control as BACT for these CTs.

Particulate Matter (PM/PM_{10})

$PM/\mathbf{PM_{10}}$ emissions are caused by incomplete combustion and traces of solids in the fuel. Proper combustion of clean fuel will emit only trace amounts of PM/PM_{10}. Each proposed CT will emit 5 lbs/hr of PM/PM_{10} or about 0.01 grains per standard cubic foot (gr/dscf). This is similar to the PM/PM_{10} emissions that can be met with the best air pollution control device, a baghouse.

BACT Determination for PM/PM_{10} for the CTs by the Department

The Department accepts an emission limit for PM/PM_{10} of 5 lbs/hr and **a visible emissions limit of** 10 percent opacity as BACT for each CT.

BACT Pollutant Analysis for the Auxiliary Boiler

Nitrogen Oxides (NO_x)

Nitrogen oxide emissions from boilers can be controlled by selective catalytic reduction (SCR), flue gas recirculation (FGR), and low-NO_x combustors.

The applicant proposes to meet a NO_x emission limit of 0.13 lbs/MMBtu through the use of low-NO_x combustors. This emission limit is below the new source performance standard for large boilers. The cost of using SCR or FGR would exceed $5,000 per ton NO_x removed.

BACT Determination for NO_x for the Auxiliary Boiler by the Department

The Department accepts an emission limit for NO_x of 0.13 lbs/MMBtu as BACT for this **auxiliary** boiler.

Particulate Matter (PM/PM_{10}), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC)

PM/PM_{10}, CO and VOC are the products of incomplete combustion of fossil fuel. The applicant proposes to meet emission limits of 0.01 lbs PM/MMBtu, 0.10 lbs CO/MMBtu, 0.04 lbs VOC/MMBtu through the use of clean fuel (natural gas/biogas) and **good** combustion control. Visible emissions shall not exceed 15 percent opacity.

BACT Determination for PM/PM_{10}, CO, and VOC for the Auxiliary Boiler by the Department

The Department accepts the use of clean fuel (natural gas/biogas) and **good** combustion controls to meet the proposed emission limits for PM/PM_{10}, CO, and VOC as BACT for this **auxiliary** boiler.

Sulfur Dioxide (SO_2)

Sulfur dioxide emissions are caused by the oxidation of sulfur in the fuel. Natural gas/biogas contains only trace amounts of sulfur - 1 grain per 100 cubic feet (gr/100 CF). This will result in an estimated sulfur dioxide emission of 0.30 lbs/hr. Cleaner fuel is not available and add on controls for SO_2 are not justified at this low emission rate.

BACT Determination for SO_2 for the Auxiliary Boiler by the Department

Natural gas/equivalent biogas fuel containing a maximum of 1 gr/100 CF is accepted as BACT for SO_2 control for this **auxiliary** boiler.

Summary of the **Revised** BACT Determination by Department

Pollutant	Emission Limits	EPA Test Methods
COMBUSTION TURBINE		
NOx	25 ppmvd @ 15% O_2 until Dec. 31, 1997	20
	15 ppmvd @ 15% O_2 after Dec. 31, 1997	**20**
CO	30 ppmvd	10
VOC	10 ppmvd	18 or 25A

PM/PM_{10}*	5 lbs/hr	5 or 17**
Visible Emissions	**10% Opacity**	**9**
AUXILIARY BOILER		
NO_x	0.13 lbs/MMBtu	7E
PM/PM_{10}*	0.01 lbs/MMBtu	5 or 17**
CO	0.10 lbs/MMBtu	10
VOC	0.04 lbs/MMBtu	18 or 25A
SO_2	1 gr sulfur/100 CF gas	fuel **sulfur** analysis
Visible Emissions	15% Opacity	9

* **Assumption is that all PM is PM_{10}.**
** Stack flue gas temperature must be less than 320°F.

Details of the Analysis May be Obtained by Contacting:
Martin Costello, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

2/24/95
Date

Approved by:

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

3-7-95
Date

1050231-002-AC
206B

Z 751 860 029

Receipt for Certified Mail
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(See Reverse)

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Street and No. Orange Co Sen	
P.O., State and ZIP Code Laguna Hills, CA	
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Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 3-7-95 AC53-233852A 53-233851B PSD-F1-206A+B	

PS Form **3800**, March 1993

Memorandum

Florida Department of Environmental Protection

Patty

TO: Virginia Wetherell, Secretary

FROM: Howard L. Rhodes, Director
Division of Air Resources Management

DATE: February 24, 1995

SUBJECT: Revision of Construction Permits and BACT
Orange Cogeneration, L.P.
AC 53-233852A & AC 53-233851B and PSD-FL-206B
Polk County

Attached for your approval and signature are two revised air construction permits and a revised Best Available Control Technology (BACT) determination for the referenced facility. The permits authorize the installation of two gas combustion turbines and one boiler in Bartow, Polk County, Florida.

The revised permits and BACT change the allowable nitrogen oxides emission standard units for the combustion turbines from a concentration at 15% oxygen and ISO standard ambient conditions to the observed concentration corrected to 15% oxygen.

I recommend your approval and signature.

HLR/wh/t

Attachments

file

ORANGE COGENERATION

Project Office: 1901 Clear Springs Road
Bartow, FL 33830
(813)-533-3399
Facsimile: (813)-533-4152

CFRB.12.FDEP

January 26, 1995

Mr. Clair Fancy
Florida Department of Environmental Protection
Station 5505
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. Willard Hanks

Subject: Revision of Construction Permits AC53-233852A and AC53-233851B

Dear Mr. Fancy:

The Permittee has reviewed the Notice of Intent to Issue Revised Permits and has one comment on the modification of the subject permits. In Permit AC53-233852B, specific condition 19 references NOx emissions of 15 ppmvd @ 15% O2 ISO conditions. Permittee requests the ISO reference be deleted from this condition, allowing the condition to be consistent with the balance of the modified permit. The deletion of this reference was noted KBN in its edit copy submitted with the October 10, 1994 request for the modification.

Please call me or Ken Kosky (904-336-5600) if there are any questions.

Very truly yours,

ORANGE COGENERATION LIMITED PARTNERSHIP
by its Authorized Representative

Thomas F. Donovan

Thomas F. Donovan
Program Manager

RECEIVED
JAN 31 1995
Bureau of
Air Regulation

cc: Bill Malenius
Ken Kosky

ORANGE COGENERATION

Project Office: 1901 Clear Springs Road
Bartow, FL 33830
(813)-533-3399
Facsimile: (813)-533-4152

CFRB.12.FDEP

January 10, 1995

Mr. John Brown
Florida Department of Environmental Protection
Station 5505
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Affidavit of Publication
Construction Permits AC53-233852A and AC53-233851B

Dear Mr. Brown:

Attached is the Affidavit of Publication for the modifications to the subject permits.

Please call me if there are any questions.

Very truly yours,

ORANGE COGENERATION LIMITED PARTNERSHIP
by its Authorized Representative

Thomas F. Donovan

Thomas F. Donovan
Program Manager

cc: Bill Malenius
M. Harris
B. Thomas, SW Dist.
J. Harper, EPA
J. Bunyak, NPS
L. Novak, Polk Co.

RECEIVED
JAN 13 1995
Bureau of
Air Regulation

AFFIDAVIT OF PUBLICATION

The Polk County Democrat

Published Semi-Weekly
Bartow, Polk County, Florida

Case No. ____________________

STATE OF FLORIDA
COUNTY OF POLK

Before the undersigned authority personally appeared ____________ Mary G. Frisbie ____________, who on oath says that (s)he is ____________ Treasurer ____________ of The Polk County Democrat, a newspaper published at Bartow, Polk County, Florida; that the attached copy of advertisement, being a Notice of Intent to Issue Revised Permit in the matter of AC53-233852A and AC53-233851B (PSD-FL-206B) ____________ in the ____________ Court, was published in said newspaper in the issues of Jan. 5, 1995.

Affiant further says that The Polk County Democrat is a newspaper published at Bartow, in said Polk County, Florida, and that said newspaper has heretofore been continuously published in said Polk County, Florida, each Monday and Thursday, and has been entered as second class matter at the post office in Bartow, in said Polk County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

Signed Mary G Frisbie

Sworn to and subscribed before me this 6th day of Jan., 1995,

by Mary G. Frisbie,

who is personally known to me.

C. Joanne Ethington
(Signature of Notary Public)

C. Joanne Ethington
(Printed or typed name of Notary Public)
Notary Public

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA
Carolyn Joanne Ethington
Comm. No. CC 425992
My Comm. Exp. Dec. 13, 1998
Bonded thru Pichard Ins. Agcy.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF INTENT TO ISSUE REVISED PERMIT AC53-233852A and AC53-233851B (PSD-FL-206B)

The Department of Environmental Protection gives notice of its intent to revise the air pollution source construction permits [AC53-233852A and AC53-2338541B (PSD-FL-206B)] issued to Orange Cogeneration Limited Partnership, 23046 Avenida De La Carlota, Suite 400 Laguna Hills, CA 92653. The permits are for a natural gas/equivalent biogas fired cogeneration facility containing two combustion turbines, an auxiliary boiler, and associated equipment. It will be located in Bartow, Polk County, Florida.

The revision is to change the allowable nitrogen oxides emission standard for the combustion turbines from a concentration at 15 percent oxygen and ISO standard ambient conditions (ppmvd @ 15% 02 at ISO) to the observed concentration corrected to 15 percent oxygen (ppmvd @ 15% 02). Also, changes are being made to the permits to reflect changes made in the revised Best Available Control Technology (BACT) determination.

This revision does not change the allowable mass emission standard (lbs/hr and TPY) of any air pollutant emitted by this facility. The facility is subject to the Prevention of Significant Deterioration (PSD) regulations. The emission standards/limitations are established by a BACT determination. The impact of the emissions will not cause or contribute to a violation of any ambient air quality standard or PSD increment.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petition filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publiciation of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The application/request 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, Department of Environmental Protection Southwest District, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

Any person may send written comments on the proposed action to Mr. John Brown at the Department of Environmental Protection, Mail Station 5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination. Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Jan. 5, 1995—0053

ORANGE COGENERATION

Project Office: 1901 Clear Springs Road
Bartow, FL 33830
(813) 533-3399
Facsimile: (813) 533-4152

CFRB.12.FDEP
VIA FACSIMILE

December 30, 1994

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, Mail Station #5505
Tallahassee, FL 32399-2400

RECEIVED
JAN 03 1995
Bureau of
Air Regulation

Attention: Mr. Willard Hanks

Subject: Permit Number AC53-233851A
Project: Two Combustion Turbines

Dear Mr. Fancy:

Specific Condition 15 of the subject permit allows the Permittee to submit by January 1, 1995 manufacturer's correction curves for the emission rate correction to other temperatures at different loads. Further the Specific Condition provides that until new curves are approved, or the NOx emission standard of 15 ppmvd @ 15% O2 is demonstrated (which ever occurs first), the stack, operator and emission data for the proposed combustion turbines in Table 2-4 (October 28, 1993) will be used to determine compliance with the maximum allowable emission rates of the regulated air pollutants at different air inlet temperatures for the combustion turbines.

The two combustion turbines proposed for the Project will be the first production models of the General Electric Company LM6000 in the United States equipped with staged combustion technology for Dry Low Emissions (DLE). General Electric has spent all of 1994 developing this DLE technology for the LM6000 CT's and is still finalizing the development program. Manufacturer correction curves have not yet been produced by General Electric and a schedule has not been set by General Electric for submission of these curves to the Permittee. The CT's for the Project were factory tested December 11 and 16. The limited data from this factory testing indicates the emission rate information presented in Table 2-4 (October 28, 1994) remains valid.

The Permittee cannot supply the Department new Manufacturer's emission rate correction curves at this time. Permittee acknowledges that compliance determination may be subject to use of the information in Table 2-4 (October 28, 1993), or to as-tested results.

OCLP
1901 Clear Springs Rd.
Bartow, Fl 33830

GMF DENVER, CO 802
PM
30 DEC
1994

Old Glory
USA G
For U.S. addresses only

Mr. Clair Fancy
Attention Willard Harley
Bureau of Air Regulation, Mail #5505
Fl Dept of Environmental Protection
2600 Blair Stone Rd
Tallahassee, Fl 32399-2400

Please feel free to call me at the office above, or Ken Kosky at 904-336-5600, with any questions.

Very truly yours,

ORANGE COGENERATION LIMITED PARTNERSHIP
by its Authorized Representative

Thomas F. Donovan

Thomas F. Donovan
Program Manager

cc: Bill Malenius
Willard Hanks
Ken Kosky

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

December 22, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Laguna Hills, CA 92653

Dear Mr. Malenius:

Re: Revision of Construction Permits
AC53-233852A and AC53-233851B (PSD-FL-206B)

The Department has reviewed KBN Engineering and Applied Sciences, Inc.'s October 10, 1994 letter requesting a change in the emission standards in the referenced permits for the combustion turbines (AC53-233851B) to be built for Orange Cogeneration Limited Partnership in Bartow, Polk County, Florida. Clarification of the emission limits for these units was also requested. In response to this request, the Department is proposing to revise the construction permit to change the units of the nitrogen oxides concentration standard to parts per million volume dry, corrected to 15 percent oxygen (ppmvd @ 15% O_2). The allowable emissions of all air pollutants from these units in pounds per hour and tons per year, which are a function of the combustion turbines air inlet temperature, are not being changed. The Department has retained the requirement for installation of nitrogen oxides and oxygen continuous emission monitors. Data from these instruments will indicate if the combustion turbines are properly operated and maintained. The Department is also retaining the requirement for compliance tests on both natural gas and biogas fuels as neither emissions or equivalency to natural gas can be estimated from an analysis of the fuels. In addition, the permit (AC53-233852A) for the auxiliary boiler is being revised to reflect changes in the testing requirements of the BACT.

Please submit the proof of publication of the attached Notice of Intent to Issue Permit and any written comments you wish to have considered concerning the Department's proposed action to Mr. John Brown on the Bureau of Air Regulation.

Sincerely,

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

CHF/WH/bjb/mc

Attachment

cc: Bill Thomas, SWD
Ken Kosky, KBN
Jewell Harper, EPA
L. Novak, PCESD
John Bunyak, NPS

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. William R. Malenius
Director of Project Development
Orange Cogeneration Limited
Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

4a. Article Number
P 872 563 679

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
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7. Date of Delivery 1-3-95

5. Signature (Addressee) Carl [illegible]

6. Signature (Agent)

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

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

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Sent to Mr. William R. Malenius	
Street and No. 23046 Avenida De La Carlota	
P.O., State and ZIP Code Laguna Hills, Ste 400 CA 92653	
Postage	$
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PS Form 3800, JUNE 1991

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF REVISED PERMIT ISSUANCE

In the Matter of an
Application for Revised Permits by:

DEP File Nos. AC53-233852A
AC53-233851B
(PSD-FL-206B)
Polk County

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653
_________________________________/

NOTICE OF INTENT TO ISSUE REVISED PERMITS

The Department of Environmental Protection (Department) gives notice of its intent to revise the permits [AC53-233852 and AC53-233851A (PSD-FL-206A)] issued for the proposed auxiliary boiler and combustion turbines, respectively, at the Orange Cogeneration Limited Partnership facility located in Bartow, Polk County, Florida.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by Petitioner, if any;

(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,

(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application/request have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE REVISED PERMITS and all copies were mailed by certified mail before the close of business on 12-29-94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

[signature] Clerk   12-29-94 Date

Copies furnished to:

B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
L. Novak, PCESD
K. Kosky, P.E., KBN

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE REVISED PERMITS

AC53-233852A and AC53-233851B (PSD-FL-206B)

The Department of Environmental Protection gives notice of its intent to revise the air pollution source construction permits [AC53-233852A and AC53-233851B (PSD-FL-206B)] issued to Orange Cogeneration Limited Partnership, 23046 Avenida De La Carlota, Suite 400, Laguna Hills, CA 92653. The permits are for a natural gas/equivalent biogas fired cogeneration facility containing two combustion turbines, an auxiliary boiler, and associated equipment. It will be located in Bartow, Polk County, Florida.

The revision is to change the allowable nitrogen oxides emission standard for the combustion turbines from a concentration at 15 percent oxygen and ISO standard ambient conditions (ppmvd @ 15% O_2 at ISO) to the observed concentration corrected to 15 percent oxygen (ppmvd @ 15% O_2). Also, changes are being made to the permits to reflect changes made in the revised Best Available Control Technology (BACT) determination.

This revision does not change the allowable mass emission standard (lbs/hr and TPY) of any air pollutant emitted by this facility. The facility is subject to the Prevention of Significant Deterioration (PSD) regulations. The emission standards/limitations are established by a BACT determination. The impact of the emissions will not cause or contribute to a violation of any ambient air quality standard or PSD increment.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The application/request 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

Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. John Brown at the Department of Environmental Protection, Mail Station 5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination. Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233851B
PSD-FL-206B
Expiration Date: April 1, 1998
County: Polk
Latitude/Longitude: 27°52'15"N
81°49'31"W
Project: Two Combustion Turbines

This revised permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of two natural gas/biogas fired GE LM 6000 (or equivalent) combustion turbines (CT), two heat recovery steam generators and one steam turbine. An auxiliary boiler (AC53-233852) is being permitted separately. The CTs will be equipped with **a staged combustion technology** dry low-NO_X system to control nitrogen oxides (NO_X) emissions. Each CT will be equipped with a 100 ft. high, 11 ft. diameter stack that will handle approximately 300,000 actual cubic feet per minute of flue gas at 230°F. The cogeneration facility will be located on Clear Springs Road, Bartow, Polk County, Florida.

The UTM coordinates of this facility are Zone 17, 418.75 km East and 3083.0 km North.

The emissions unit(s)/sources shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

<u>Attachments are listed below</u>:
1. Application received July 1, 1993.
2. Department's July 22, 1993 letter.
3. KBN's August 5, 1993 letter.
4. KBN's August 29, 1993 letter.
5. Tables 1 and 2, Allowable Emission Rates.
6. KBN's October 28, 1993 letter.
7. KBN's October 29, 1993 letter.
8. Department's February 18, 1994 letter.
9. KBN's March 11, 1994 letter.
10. Department's March 29, 1994 letter.
11. KBN's June 22, 1994 letter.
12. KBN's October 10, 1994 letter.

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

a. a description of and cause of non-compliance; and,

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

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

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

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

GENERAL CONDITIONS:

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

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

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;
        - the analytical techniques or methods used; and,
        - the results of such analyses.

GENERAL CONDITIONS:

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

SPECIFIC CONDITIONS:

This permit replaces permit No. AC53-233851/PSD-FL-206 and amended construction permit No. AC53-233851A/PSD-FL-206A.

Construction Requirements

1. Dry low-NO_X **combustion technology** systems shall be installed and operated on each combustion turbine (CT).

2. A system to continuously monitor the fuel consumption, nitrogen oxides emissions, and oxygen content of the flue gas shall be installed on each CT.

3. The heat recovery steam generator (HRSG) installed on each CT shall not be equipped with an auxiliary/duct burner.

4. Each CT stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, and electrical power) that meet the specifications given in Rule 62-297.345, F.A.C.

Operation Limitations

5. The CTs shall comply with all requirements of 40 CFR 60, Subpart GG (July, 1993), Standard of Performance for Stationary Gas Turbines, which is adopted by reference in Rule 62-296.800(2)(a), F.A.C.

6. The facility is allowed to operate continuously, 8760 hours per year.

7. Only natural gas/biogas fuel shall be used for fuel at this facility.

8. Each CT shall have a maximum heat input of 368.3 MMBtu/hr, when using dry low NO_X technology to control NO_X emissions.

9. The operation of this facility shall not create a nuisance or discharge air pollutants that cause or contribute to objectionable odors **pursuant to Rule 62-296.320(2), F.A.C.**

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851B (PSD-FL-206B)
42 MW COMBINED CYCLE GAS TURBINES

Table 1 - Allowable Emission Rates[b] for each Combustion Turbine

		Allowable Emissions Standards/Limitations				
			Compl.	Maximum Corrected[c]		Basis for
Pollutant[a]	Control[e]	Concentration	Date	lbs/hr	TPY	Limit
NO_x	DLN	25 ppmvd at 15% O_2[d]	initial	37.0	161.9	BACT
	DLN	**15 ppmvd at 15% O_2[d]**	**1/1/98**	**22.1**	**97.0**	**BACT**
CO	GC[f]	30 ppmvd		27.8	127.0	BACT
PM/PM_{10}	GC[f]			5	21.9	BACT
VOC	GC[f]	10 ppmvd		3.98	17.4	BACT

[a] Pollutant emissions are based on 8,760 hours per year operation firing natural gas or biogas.

[b] Allowable emissions, lbs/hr, at different inlet temperatures shall not exceed the rates given in the manufacturer's data required by specific condition No. 15.

[c] Maximum emission rates not to be exceeded.

[d] The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the initial compliance demonstration stack tests are performed, the permittee must provide the Department with a plan and schedule to meet this standard. NO_x emission concentrations are to be corrected to 15 percent oxygen to demonstrate compliance with the NO_x emissions standard.

[e] Dry Low-NO_x (DLN) combustors.

[f] Good Combustion.

SPECIFIC CONDITIONS:

Emission Limitation

10. Prior to January 1, 1998, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit, shall not exceed 25 parts per million by volume dry corrected to 15 percent oxygen (25 ppmvd @ 15% O_2), as determined by the procedures in Specific Conditions Nos. 16, 17 and 18.

11. After December 31, 1997, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit, shall not exceed 15 ppmvd @ 15% O_2, as determined by the procedures in Specific Conditions Nos. 16, 17 and 18. Should the NO_x standard of 15 ppmvd @ 15% O_2 not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard. The permittee shall obtain prior approval from the Department for any air pollution control equipment not addressed in this permit that is needed to meet the NO_x emission standard.

12. The maximum emission rates for particulate matter (PM/PM_{10}), volatile organic compounds (VOC), NO_x, and carbon monoxide (CO) shall not exceed any of the rates listed in Table 1, Allowable Emission Rates.

13. Visible emissions shall not exceed 10 percent opacity, 6 minute average.

14. The emission rates for sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist, listed in the following table, shall be used for inventory purposes only.

Maximum Emission Rates for Each Combustion Turbine
For Inventory and PSD Tracking Purposes Only

Pollutant	Combustion Turbine Dry Low NO_x Combustion lb/hr	Combustion Turbine Dry Low NO_x Combustion TPY
SO_2	1.11	4.87
H_2SO_4 mist	0.085	0.37

15. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review **by January 1, 1995.** Until new curves are approved by the Department or the combustion turbines meet the NO_x emission standard of 15 ppmvd @ 15% (whichever occurs first), the stack, operator, and emission data for the proposed combustion turbines in

SPECIFIC CONDITIONS:

Table 2-4 **(October 28, 1993)** will be used. The data will be used to determine compliance with the maximum allowable emission rates of the regulated air pollutants at different air inlet temperatures for these turbines.

Compliance Determination

16. Testing of emissions shall be conducted at **95-100%** of the manufacturer's rated heat input based on the **average air inlet temperature** for the CT during the test. **Compliance for NO_x emission limits shall be determined by calculating the concentration of NO_x (ppmvd at 15% O_2) and using the turbine manufacturer's thermal throughput rating for the average air inlet temperature by multiplying the permitted emission limit by the ratio of the tested heat input to the maximum heat input (MMBtu/hr) at this temperature.** Compliance with the visible emissions, NO_x, SO_2, CO, PM/PM_{10}, and VOC emission standards shall be determined within 60 days of achieving maximum production but not later than 180 days after initial firing of each CT (40 CFR 60.8). Compliance with the visible emissions **limitation and the** NO_x and SO_2 **emission** standards shall be determined annually thereafter. **Tests shall be conducted on both natural gas and biogas fuels. If the initial tests or fuel analyses show the emissions of air pollutants from the combustion turbines are independent of the fuel (natural gas or biogas fuel), then annual compliance tests can be conducted while the combustion turbines are burning either fuel.**

17. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

Pollutant	EPA Method
PM/PM_{10}*	5 or 17**
NO_x	20
CO	10
VOC	18 or 25A
Visible Emissions	9

NOTE: No other test methods may be used for compliance testing **unless** prior Department **written** approval **has been received.**
* **Assumption is that all PM is PM_{10}.**
** Stack flue gas temperature must be less than 320°F to use Method 17.

SPECIFIC CONDITIONS:

Monitoring

18. **NO_x and oxygen monitoring to meet the requirements of 40 CFR 60, Subpart GG, shall be accomplished using a continuous emission monitoring (CEM) system. The CEM system shall meet the requirements of 40 CFR 60, Appendix B. The requirements of 40 CFR 75, Appendices A and B, can be substituted for those of 40 CFR 60 provided the minimum criteria of 40 CFR 60 are met. NO_x monitoring to indicate compliance with the BACT limit shall be based on one hour average emissions determined on ppmvd @ 15% O_2.**

Administrative Requirement

19. Prior to January 1, 1998, the permittee shall provide a report showing how the allowable NO_x emissions of 15 ppmvd @ 15% O_2 ISO conditions is achieved by the CTs.

20. The permittee shall provide the Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction
- Anticipated date of initial starting 30 to 60 days prior to startup
- Actual date of startup up within 15 days after the starting
- Notification of the date of the compliance tests not less than 30 days prior to the test

21. Pursuant to Rule 62-210.370(2), F.A.C., Air Operating **Reports**, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, and air emissions. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

22. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the **Department's** Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

23. An application for an operation permit must be submitted to the **Department's** Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the

SPECIFIC CONDITIONS:

construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

____
Virginia B. Wetherell, Secretary

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233852A
PSD-FL-206B
Expiration Date: April 1, 1996
Latitude/Longitude: 27°52'15"N
81°49'31"W
Project: Auxiliary Boiler
County: Polk

This revised permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of a 100 million British thermal unit per hour (MMBtu/hr) natural gas/equivalent biogas fired tube boiler equipped with a 65 foot high, 3.67 foot diameter stack designed to produce approximately 83,000 pounds per hour of saturated steam at 205 pounds per square inch gauge (psig) pressure. The heat input is based on the High Heating Value (HHV) of the fuel. The auxiliary boiler will be located on Clear Springs Road, Bartow, Polk County, Florida 33830.

The UTM coordinates of this facility are Zone 17, 418.75 kmE and 3083.0 kmN.

The emission unit/source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. Application received July 1, 1993.
2. Department's July 22, 1993 letter.
3. KBN's August 5, 1993 letter.

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. A description of and cause of non-compliance; and,

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

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

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

GENERAL CONDITIONS:

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

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

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

13. This permit also constitutes:

    (X) Determination of Best Available Control Technology (BACT)
    (X) Determination of Prevention of Significant Deterioration (PSD)
    (X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and,
- the results of such analyses.

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

SPECIFIC CONDITIONS:

Construction Requirements

1. The auxiliary boiler shall be equipped with low-NO_X burners.

2. The boiler stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, electrical power) that meet the specifications given in Rule 62-297.345, F.A.C.

Operation Limitations

3. The auxiliary boiler shall comply with all applicable requirements of 40 CFR 60, Subpart Dc.

4. The boiler is allowed to operate continuously, 8760 hours per year.

5. Only natural gas/equivalent biogas fuel shall be burned in this boiler.

6. The maximum heat input to the boiler, **which is** based on the high heating value (HHV) of the fuel, shall not exceed 100 MMBtu/hr.

7. The maximum allowable sulfur content (total) of the natural gas/biogas burned in the boiler shall not exceed 1 grain per 100 cubic feet (1 gr/100 CF) of gas.

SPECIFIC CONDITIONS:

8. The operation of this boiler shall not emit air pollutants that cause or contribute to objectionable odors.

9. Visible emissions shall not exceed 15 percent opacity.

10. Emissions from the boiler shall not exceed any of the following limits:

Pollutant	lb/MMBtu	lbs/hr	TPY
NO_x	0.13	13.0	56.9
CO	0.10	10.0	43.8
VOC	0.04	4.3	18.8

11. Sulfur dioxide (SO_2) emissions from the boiler shall not exceed 0.003 lb/MMBtu, 0.30 lb/hr, and 1.3 TPY. An analysis of the fuel showing the sulfur content does not exceed 1 grain of total sulfur per 100 cubic feet of gas will be accepted as proof of compliance with the sulfur dioxide emission limit. Total sulfur content of the gas shall be determined by test method ASTM D 1072-80 (40 CFR 60.17 (July, 1993)).

12. Particulate matter (PM/PM_{10}) emissions from the boiler shall not exceed 0.01 lb/MMBtu, 1.0 lb/hr, and 4.4 TPY. No PM/PM_{10} stack test is required if the visible emissions **limitation is** less than 15 percent opacity.

Testing Requirements

13. Testing of emissions shall be conducted with the source operating at **permitted** capacity. Capacity is defined as 90-100% of **the maximum operating rate allowed by the permit.** If it is impracticable to test at **permitted** capacity, then sources may be tested at less than **90% of the maximum operating rate allowed by the permit.** In this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Compliance with the visible emissions **limitation and the** NO_x, CO, and VOC emission standards shall be determined within 60 days of achieving maximum production, but not later than 180 days after initial firing of the boiler. Compliance with the visible emissions **limitation** and **the** NO_x **emission** standards shall be determined annually thereafter.

SPECIFIC CONDITIONS:

14. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

Pollutant	EPA Method
PM/PM_{10}*	5 or 17**
NO_x	7E
CO	10
VOC	18 or 25A
Visible Emissions	9

NOTE: No other test methods may be used for compliance testing **unless** prior Department **written** approval **has been received.**
*** Assumption is that all PM is PM_{10}.**
**** Stack flue gas temperature must be less than 320°F for Method 17.**

15. The permittee shall provide the Department's Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction.
- Anticipated date of initial startup, 30 to 60 days prior to startup.
- Actual date of startup within 15 days after the startup.
- Notification of the date of the compliance tests not less than 30 days prior to the tests.

16. Pursuant to Rule 62-210.370(2), F.A.C., Air Operating **Reports**, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emission limits, etc. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

17. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

18. An application for an operation permit must be submitted to the Department's Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the

SPECIFIC CONDITIONS:

appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

____
Virginia B. Wetherell, Secretary

Revised Best Available Control Technology (BACT) Determination
Orange Cogeneration Limited Partnership
Polk County
AC53-233852A and AC53-233851B (PSD-FL-206B)

The applicant proposes to construct a 103 gross megawatt (MW) natural gas/biogas fired cogeneration facility in Bartow, Polk County, Florida. Major components of the cogeneration facility are: two combustion turbines (CT), each with a heat recovery steam generator (HRSG), an auxiliary boiler, steam turbine generator, and associated equipment. Both CTs will consume up to 776 million British thermal units per hour (MMBtu/hr) of gas fuel based on the lower heating value (LHV) of the fuel and produce 78 MW of electricity. The HRSGs, which do not use supplemental fuel, produce approximately 100,000 lbs/hr of steam and generate 25 MW of electricity. The fire-tube auxiliary boiler will consume 100 MMBtu/hr of gaseous fuel and produce approximately 83,000 lbs/hr of steam.

The following table lists the estimated maximum emissions from the cogeneration facility.

	Two CTs		Auxiliary Boiler	
Pollutant	lbs/hr	TPY	lbs/hr	TPY
Sulfur dioxide (SO_2)	2.34	10.3	0.3	1.3
Particulate Matter (PM/PM_{10})	10	43.8	1.0	4.4
Nitrogen Oxide (NO_x)	77.0	336.9	13.0	56.9
Carbon Monoxide (CO)	55.6	243.9	10.0	43.8
Volatile Organic Compounds (VOC)	7.96	34.9	4.3	18.8
Sulfuric Acid Mist	0.18	0.79	0.023	0.1

The cogeneration facility requires a BACT determination for NO_x, CO, PM, and VOC. In addition, the auxiliary boiler requires a BACT determination for **PM and** SO_2.

Date of Receipt of a BACT Application

July 1, 1993

BACT Requested by the Applicant

Pollutant	Proposed Limit	Air Pollution Control
Combustion Turbine		
PM	0.01 gr/scf*	Clean Fuel (gas) and
NO_x	25 ppmvd @ 15%**	Dry Low-NOx Combustors
	15 ppmvd @ 15%**	

CO	30 ppmvd	Combustion Controls
VOC	10 ppmvd	Combustion Controls

Auxiliary Boiler

PM	0.01 lbs/MMBtu	Clean Fuel (gas)
NO_x	0.13 lbs/MMBtu	Low-NO_x burners
SO_2	1 grain/100 CF natural gas	Clean Fuel (natural gas)
CO	0.10 lbs/MMBtu	Combustion Control
VOC	0.043 lbs/MMBtu	Combustion Control

*grains per standard cubic foot
**parts per million by volume dry at 15 percent oxygen
Applicant is committed to meeting 15 ppmvd @ 15% O_2 with dry low-NO_x combustors after December 31, 1997.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 62-212, 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, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from cogeneration facilities 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 matter). 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.

Although all of the pollutants addressed in the BACT analysis may be subjected 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, 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 for the Combustion Turbines (CTs)

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 control technologies evaluated were selective catalytic reduction (SCR), wet injection (WI), dry low-NO_X combustor, NO_XOUT process, thermal DeNO_X, and selective noncatalytic reduction (SNCR).

NO_XOUT (urea with catalyst), thermal DeNO_X (ammonia with catalyst), and selective noncatalytic reduction system (ammonia without catalyst) to reduce NO_X emissions from the CT were not feasible because of process constraints (flue gas temperature too low and oxygen content too high).

SCR, dry low-NO_X combustor technology, and wet injection controls were considered feasible.

The applicant has stated that BACT for nitrogen oxides will be met by using advanced combustor design to limit emissions to 25 ppmvd @ 15% O_2, when burning natural gas/biogas. After December 31, 1997, a limit of 15 ppmvd @ 15% O_2 will be met. Should 15 ppmvd NO_x @ 15% O_2 not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard.

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 SCR system.

SCR 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 though the catalyst bed. With a new catalyst, the SCR process can achieve up to 90% reduction of NO_x. As the catalyst ages, the maximum NO_x reduction will decrease.

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°F.

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.

Although technically feasible, the applicant has 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 (spent 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) The energy impacts of SCR will reduce potential electrical power generation by 0.8 percent.

f) Incremental cost effectiveness for the application of SCR technology to the Orange Cogeneration L.P. project was considered to be $7,970 when emissions are at 25 ppm and $23,510 when emissions are at 15 ppm. Since SCR has been determined to be BACT for gas turbines, 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 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."

The cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR.

A concern associated with the use of SCR on combustion turbines 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 in some previous BACT determinations. This salt also increases particulate matter (PM/PM_{10}) emissions.

For natural gas/equivalent biogas 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. 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 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 on two CTs for this project at 100 percent capacity factor and burning natural gas/equivalent biogas is $1,648,000. A SCR would reduce the NO_x emissions by 207 TPY during the first 2 years of operation when the CTs emit 25 ppmvd @ 15% O_2. Thereafter, when dry-low NO_x controls are used, a SCR would reduce NO_x emissions by 120 TPY. When these reductions are taken into consideration, the total cost with SCR is $21,900 per ton of NO_X removed. This calculated cost is higher than has previously been approved as BACT.

A review of the latest Department BACT determinations show limits of 15 ppmvd (natural gas) using **dry** low-NO_X **combustor** technology for gas turbines. Most combustion turbine manufacturers are currently developing programs using both steam/water injection and dry low-NO_X combustor **technology** to achieve **a** NO_X emission control level of 9 ppm when firing natural gas. Therefore, this technology will likely be available by 1998.

<u>BACT Determination for NO_X for the CTs by the Department</u>

<u>NO_X Control</u>

The information that the applicant presented and Department calculation indicate that the cost per ton of controlling NO_X for this turbine [$21,900 per ton] 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 combustion turbine 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/steam injection and **dry** low-NO_X **combustor technology** design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that combustion turbine manufacturers are developing programs 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.

Based on this, the Department has determined to revise and lower the allowable BACT limit for this project to 15 ppmvd at 15% O_2 **and is to be achieved** no later than 1/1/98.

<u>Carbon Monoxide (CO)</u>

CO emissions are caused by incomplete combustion of the fossil fuel. The applicant investigated the use of combustion control and catalytic oxidation to control CO emission. With combustion control, CO emissions would be 30 ppmvd (236 TPY). With catalytic oxidation, CO emissions would be 10 ppmvd (78 TPY). The annualized cost of the catalyst system is $834,700 or $5,280 per ton of CO removed.

BACT Determination for CO for the CTs by the Department

Because catalytic oxidation would increase operation cost by $5,280 per ton of CO removed, and have no significant reduction in ambient air quality, the Department accepts an emission limit for CO of 30 ppmvd obtained through combustion control as BACT for these CTs.

Volatile Organic Compounds (VOC)

VOC emissions are caused by incomplete combustion of fossil fuel. The applicant proposes to meet an emission limit of 10 ppmvd through the use of clean fuel (natural gas) and combustion controls. This is similar to the BACT applied to other **similar** sources.

BACT Determinations for VOC for the CTs by the Department

The Department accepts an emission limit for VOC of 10 ppmvd obtained through the use of clean fuel (natural gas) and combustion control as BACT for these CTs.

Particulate Matter (PM/PM_{10})

PM/PM_{10} emissions are caused by incomplete combustion and traces of solids in the fuel. Proper combustion of clean fuel will emit only trace amounts of PM/PM_{10}. Each proposed CT will emit 5 lbs/hr of PM/PM_{10} or about 0.01 grains per standard cubic foot (gr/dscf). This is similar to the PM/PM_{10} emissions that can be met with the best air pollution control device, a baghouse.

BACT Determination for PM/PM_{10} for the CTs by the Department

The Department accepts an emission limit for PM/PM_{10} of 5 lbs/hr and **a visible emissions limit of** 10 percent opacity as BACT for each CT.

BACT Pollutant Analysis for the Auxiliary Boiler

Nitrogen Oxides (NO_x)

Nitrogen oxide emissions from boilers can be controlled by selective catalytic reduction (SCR), flue gas recirculation (FGR), and low-NO_x combustors.

The applicant proposes to meet a NO_x emission limit of 0.13 lbs/MMBtu through the use of low-NO_x combustors. This emission limit is below the new source performance standard for large boilers. The cost of using SCR or FGR would exceed $5,000 per ton NO_x removed.

BACT Determination for NO_x for the Auxiliary Boiler by the Department

The Department accepts an emission limit for NO_x of 0.13 lbs/MMBtu as BACT for this **auxiliary** boiler.

Particulate Matter (PM/PM_{10}), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC)

PM/PM_{10}, CO and VOC are the products of incomplete combustion of fossil fuel. The applicant proposes to meet emission limits of 0.01 lbs PM/MMBtu, 0.10 lbs CO/MMBtu, 0.04 lbs VOC/MMBtu through the use of clean fuel (natural gas/biogas) and **good** combustion control. Visible emissions shall not exceed 15 percent opacity.

BACT Determination for PM/PM_{10}, CO, and VOC for the Auxiliary Boiler by the Department

The Department accepts the use of clean fuel (natural gas/biogas) and **good** combustion controls to meet the proposed emission limits for PM/PM_{10}, CO, and VOC as BACT for this **auxiliary** boiler.

Sulfur Dioxide (SO_2)

Sulfur dioxide emissions are caused by the oxidation of sulfur in the fuel. Natural gas/biogas contains only trace amounts of sulfur - 1 grain per 100 cubic feet (gr/100 CF). This will result in an estimated sulfur dioxide emission of 0.30 lbs/hr. Cleaner fuel is not available and add on controls for SO_2 are not justified at this low emission rate.

BACT Determination for SO_2 for the Auxiliary Boiler by the Department

Natural gas/equivalent biogas fuel containing a maximum of 1 gr/100 CF is accepted as BACT for SO_2 control for this **auxiliary** boiler.

Summary of the **Revised** BACT Determination by Department

Pollutant	Emission Limits	EPA Test Methods
COMBUSTION TURBINE		
NOx	25 ppmvd @ 15% O_2 until Dec. 31, 1997	20
	15 ppmvd @ 15% O_2 after Dec. 31, 1997	**20**
CO	30 ppmvd	10
VOC	10 ppmvd	18 or 25A

PM/PM_{10}*	5 lbs/hr	5 or 17**
Visible Emissions	**10% Opacity**	**9**
AUXILIARY BOILER		
NO_x	0.13 lbs/MMBtu	7E
PM/PM_{10}*	0.01 lbs/MMBtu	5 or 17**
CO	0.10 lbs/MMBtu	10
VOC	0.04 lbs/MMBtu	18 or 25A
SO_2	1 gr sulfur/100 CF gas	fuel **sulfur** analysis
Visible Emissions	15% Opacity	9

* **Assumption is that all PM is PM_{10}.**
** Stack flue gas temperature must be less than 320°F.

Details of the Analysis May be Obtained by Contacting:
Martin Costello, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by: Approved by:

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

Date

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

Date

Memorandum

Florida Department of
Environmental Protection

TO: Virginia B. Wetherell

FROM: Howard L. Rhodes

DATE: August 9, 1994

SUBJECT: Amendment of Permit
Orange Cogeneration L.P.

Attached for your approval and signature is an amended (reissued) permit to construct two cogeneration units in Bartow, Polk County, Florida. The original construction permit was issued on December 30, 1993. It was amended in February, 1994, to allow the permittee to update the performance curves for the combustion turbines. The permittee is now asking for additional time to provide the performance curves for the combustion turbine and clarification of some operation, monitoring, and testing requirements. The reissued permit incorporates all approved amendments since the original permit was issued.

I recommend your approval of the amended (reissued) construction permit.

Attachment

CHF/WH/bjb

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT ISSUANCE

CERTIFIED MAIL

In the Matter of an Application for Permit by:

DEP File No. AC53-233851A
Polk County

Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota, Suite 400
Laguna Hills, California 92650
_______________________________/

Enclosed is revised Permit Number AC53-233851A to construct two natural gas/equivalent biogas fired gas turbines with heat recovery steam generators and a steam turbine in Bartow, Polk County, Florida. This permit is being revised to allow additional time for the permittee to furnish the manufacturer's curves for the combustion turbine, clarify the monitoring and testing requirements, and to make footnote[d] of Table 1 consistent with Specific Condition No. 11. This permit is issued pursuant to Chapter 403, Florida Statutes, and Chapters 17-212 and 17-4, Florida Administrative Code.

A person whose substantial interests are affected by this permit may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of receipt of this Permit. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and

(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

This permit is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition and conforms to Rule 17-103.070, F.A.C. Upon timely filing of a petition or a request for an extension of time this permit will not be effective until further Order of the Department.

When the Order (Permit) is final, any party to the Order has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Final Order is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

James K. Pennington

for C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

<u>CERTIFICATE OF SERVICE</u>

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT ISSUANCE and all copies were mailed by certified mail before the close of business on 8/16/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell (Clerk) 8/16/94 (Date)

Copies furnished to:
- B. Thomas, SWD
- J. Harper, EPA
- J. Bunyak, NPS
- L. Novak, PCESD
- R. Koshy, KBN (8-25-94)

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233851A
PSD-FL-206A
Expiration Date: April 1, 1998
County: Polk
Latitude/Longitude: 27°52'15"N
81°49'31"W
Project: Two Combustion Turbines

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of two natural gas/equivalent biogas fired GE LM 6000 (or equivalent) combustion turbines (CT), two heat recovery steam generators, one steam turbine and, being permitted separately, an auxiliary boiler (AC53-233852). The CTs will be equipped with **a staged combustion technology** dry low NO_X system to control nitrogen oxides (NO_X) emission. Each CT will be equipped with a 100 ft. high, 11 ft. diameter stack that will handle approximately 300,000 actual cubic feet per minute of flue gas at 230°F. The cogeneration facility will be located on Clear Springs Road, Bartow, Polk County, Florida 33830.

The UTM coordinates of this facility are Zone 17, 418.75 kmE and 3083.0 kmN.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

This permit replaces permit Nos. AC53-233851 and PSD-FL-206.

<u>Attachments are listed below:</u>

1. Application received July 1, 1993
2. DEP July 22, 1993, letter
3. KBN August 5, 1993, letter
4. KBN August 29, 1993, letter
5. Tables 1 and 2, Allowable Emission Rates
6. KBN October 28, 1993, letter
7. KBN October 29, 1993 letter
8. DEP February 18, 1994, letter
9. KBN March 11, 1994, letter
10. DEP March 29, 1994, letter
11. KBN June 22, 1994, letter

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. A description of and cause of non-compliance; and

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

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

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

GENERAL CONDITIONS:

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

(X) Determination of Best Available Control Technology (BACT)
(X) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

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

SPECIFIC CONDITIONS:

Construction Requirements

1. Dry low NO_x **combustion technology** systems shall be installed and operated on each combustion turbine (CT).

2. A system, accurate to within 5 percent, to continuously monitor the fuel consumption shall be installed on each CT.

3. The heat recovery steam generator (HRSG) installed on each CT shall not be equipped with an auxiliary/duct burner.

4. Each CT stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, and electrical power) that meet the specifications given in F.A.C. Rule 17-297.345.

Operation Limitations

5. The CTs shall comply with all requirements of 40 CFR 60, Subpart GG (July, 1993), Standard of Performance for Stationary Gas Turbines, which is adopted by reference in F.A.C. Rule 17-296.800(2)(a).

SPECIFIC CONDITIONS:

6. The facility is allowed to operate continuously, 8760 hours per year.

7. Only natural gas/equivalent biogas fuel shall be used for fuel at this facility.

8. Each CT shall have a maximum heat input (LHV) of 368.3 MMBtu/hr, which is approximately 389,300 CFH of natural gas, when using dry low NO_x technology to control NO_x emissions.

9. The operation of this facility shall not create a nuisance or discharge air pollutants that cause or contribute to objectionable odors.

<u>Emission Limitation</u>

10. Prior to January 1, 1998, the maximum NO_x concentration, 1 hour average, from each CT/HRSG unit shall not exceed 25 parts per million by volume dry corrected to 15 percent oxygen at ISO standard ambient conditions (ppmvd @ 15% O_2 at ISO conditions), as determined by the procedures in Specific Conditions No. 16, 17 and 18.

11. After December 31, 1997, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit shall not exceed 15 ppmvd @ 15% O_2 at ISO conditions as determined by the procedure in Specific Conditions Nos. 16, 17 and 18. Should 15 ppmvd NO_x @ 15% O_2 at ISO conditions not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard. The permittee shall obtain prior approval from the Department for any air pollution control equipment not addressed in this permit that is needed to meet the NO_x emission standard.

12. The maximum emission rates for particulate matter (PM/PM_{10}), volatile organic compounds (VOC), NO_x, and carbon monoxide (CO) shall not exceed any of the rates listed in Table 1, Allowable Emission Rates.

13. Visible emissions shall not exceed 10 percent opacity, 6 minute average.

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851 (PSD-FL-206)
42 MW COMBINED CYCLE GAS TURBINE

Table 1 - Allowable Emission Rates for each Combustion Turbine

			Allowable Emissions Standards/Limitations				
			ISO Conditions[b]		Maximum Corrected[c]		Basis for
Pollutant[a]	Control[e]	Basis	lb/hr	TPY	lb/hr	TPY	Limit
NO_x	DLN	25 ppmvd at 15% O_2/ISO at full load	34.8	152.3	37.0	161.9	BACT
CO	DLN	30 ppmvd	27	118.2	27.8	127.0	BACT
PM/PM_{10}	DLN	5 lb/hr	5	21.9	5	21.9	BACT
VOC	DLN	10 ppmvd	3.86	16.9	3.98	17.4	BACT

[a] Pollutant emissions are based on 8,760 hours per year operation firing natural gas or equivalent biogas at 59° F.

[b] Emissions rates are based on 100% load and at ISO conditions. Pollutant emission rates may vary depending on the air inlet temperature to the combustion turbine (CT) and CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review by January 1, 1995. Subject to approval by the Department, the manufacturer's curve shall be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination.

[c] Maximum emission rates not to be exceeded.

[d] The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 at ISO conditions by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the initial compliance demonstration stack tests are performed, the permittee must provide the Department with a plan and schedule to meet this standard. NO_x emission concentrations are to be corrected to ISO conditions to demonstrate compliance with the NO_x emissions standard.

[e] Dry Low-NO_x (DLN) combustors.

SPECIFIC CONDITIONS:

14. The emission rates for sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4), listed in the following table, shall be used for inventory purposes only.

Maximum Emission Rates for Each Combustion Turbine for inventory purposes or PSD tracking

Pollutant	Combustion Turbine Dry Low NO_x Combustion	
	lb/hr	TPY
SO_2	1.11	4.87
H_2SO_4	0.085	0.37

15. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review **by January 1, 1995.** Until new curves are approved by the Department or the combustion turbines meet the NO_x emission standard of 15 ppmvd @ 15% at ISO conditions (whichever occurs first), the stack, operator, and emission data for the proposed combustion turbines in Table 2-4 **(October 28, 1993)** will be used. The data will be used to determine compliance with the maximum allowable emission rates of the regulated air pollutants at different air inlet temperatures for these turbines.

Compliance Determination

16. Testing of emissions shall be conducted at **95-100%** of the manufacturer's rated heat input based on the **average air inlet temperature** for the CT during the test. **Compliance for NO_x emission limits shall be determined by calculating the concentration of NO_x (ppmvd at 15% O_2 at ISO) and using the turbine manufacturer's thermal throughput rating for the average air inlet temperature by multiplying the permitted emission limit at ISO conditions (59°F) by the ratio of the tested heat input to the maximum heat input (MMBtu/hr) at ISO conditions.** Compliance with the visible emissions, NO_x, SO_2, CO, PM/PM_{10}, and VOC emission standards shall be determined within 60 days of achieving maximum production but not later than 180 days after initial firing of each CT (40 CFR 60.8). Compliance with the visible emission, NO_x, and SO_2 standards shall be determined annually thereafter. **Unless fuel analyses show the composition of natural gas and the biogas are identical, tests shall be conducted on both natural gas and biogas fuels. If the initial tests or fuel analyses show the emissions of air pollutants from the combustion turbines are independent of the fuel (natural gas or equivalent biogas fuel), then annual compliance tests can be conducted while the combustion turbines are burning either fuel.**

SPECIFIC CONDITIONS:

17. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

EPA Method	Pollutant
5, 17*, or 201A and 202	PM/PM_{10}
9	Visible Emissions
10	CO
20	NO_x and SO_2
18, 25, or 25A	VOC

Other test methods may be used for compliance testing after prior Department approval.

*Stack flue gas temperature must be less than 320°F to use Method 17.

18. **NO_x and oxygen monitoring to meet the requirements of 40 CFR 60, Subpart GG, shall be accomplished using a continuous emission monitoring (CEM) system. The CEM system shall meet the requirements of 40 CFR 60, Appendix B. The requirements of 40 CFR 75, Appendices A and B, can be substituted for those of 40 CFR 60 provided the minimum criteria of 40 CFR 60 are met. NO_x monitoring to demonstrate performance with the BACT limit shall be based on one hour average emissions determined on ppmvd @ 15% O_2 at ISO conditions.**

Administrative Requirement

19. Prior to January 1, 1998, the permittee shall provide a report showing how the allowable NO_x emissions of 15 ppmvd @ 15% O_2 ISO conditions is achieved by the CTs.

20. The permittee shall provide the Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction
- Anticipated date of initial starting 30 to 60 days prior to startup
- Actual date of startup up within 15 days after the starting
- Notification of the date of the compliance tests not less than 30 days prior to the test

21. Pursuant to F.A.C. Rule 17-210.300(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, and air emissions. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

SPECIFIC CONDITIONS:

22. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

23. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. William R. Malenius
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, California 92650

4a. Article Number
P 872 562 710

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

7. Date of Delivery 8-19-94

5. Signature (Addressee)

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

6. Signature (Agent)
Cindy Shore

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 710

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to	Mr. William R. Malenius
Street and No.	23046 Avenida De La Carlota
P.O., State and ZIP Code	Laguna Hills, CA 92650
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	Mailed: 8/16/94 AC53-233851A

PS Form 3800, JUNE 1991

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. ~~Fancher~~ AH 7/18
2. ~~Linton~~ JB
3. Clair
4. Howard
5. Virginia

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE ________

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

____ FOR YOUR FILES

COMMENTS:

Proposed Response to KBN's Request to amend Orange Cogen. Const. permit.

Request received 6/23/94

Fee requested 6/27/94

Fee received 7/1/94

The marked up copy of the Const permit attached to KBN's 6/22/94 letter shows the areas of the permit that were amended

FROM: wmh DATE: 7/13/94 PHONE: ________

DEP 15-026 (12/93)

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Kennard F. Kosky, P.E.
President
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

4a. Article Number
P 872 562 715

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

7. Date of Delivery
6-29

5. Signature (Addressee)
M. Ozment

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

6. Signature (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 715

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to	Mr. Kennard F. Kosky, P.E.
Street and No.	1034 NW 57th Street
P.O., State and ZIP Code	Gainesville, FL 32605
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	Mailed: 6/27/94 AC 53-233851, PSD-FL-206

PS Form **3800**, JUNE 1991

ORANGE
COGENERATION

RECEIVED
APR 29 1996
BUREAU OF
AIR REGULATION

April 23, 1996

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Sir:

I am writing on behalf of Orange Cogeneration Limited Partnership to ensure that you have the proper address and person for correspondence and notifications regarding the Orange Cogeneration Facility located at 1901 Clear Spring Road, Bartow, Florida.

Your agency issued the following permits during the construction of the Orange Cogeneration Facility.

- Permit AC53-233851;AC53-233852; PSD-FL-206 - Permit to Operate/Construct Air Pollution Sources

Please address any future correspondence regarding the permit listed above to:

Allan Wade Smith
General Manager
Orange Cogeneration GP, Inc.
1125 US Hwy 98 South, Suite 100
Lakeland, Florida 33801

Nancy Jones

Also, please forward a copy of any correspondence to the facility operator at the address below:

Manager of Cogeneration
CSWE Operations
1901 Clear Spring Road
Bartow, Florida 33830

John Paul Jones

If you have any questions please call me at (941) 682-6338.

4-30-96
CCW

Sincerely,

Orange Cogeneration Limited Partnership
by its General Partner

Allan W. Smith

Polk Power

Allan W. Smith
General Manager
Orange Cogeneration GP, Inc.

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

June 27, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

Dear Mr. Kosky:

RE: Orange Cogeneration Limited Partnership
Permit No. AC 53-233851, PSD-FL-206

The Bureau of Air Regulation received your June 22, 1994, request for the above referenced project. The changes requested in your letter will necessitate an amendment to your permit and, pursuant to Rule 17-4.050(4)(o), F.A.C., will require a $250 fee. As soon as the fee is received we will begin processing your request. If you have any questions, please call Patty Adams at (904)488-1344.

Sincerely,

Patty Adams

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

CHF/pa

June 22, 1994

RECEIVED

JUN 23 1994

Bureau of
Air Regulation

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Orange Cogeneration Limited Partnership
Permit Application AC 53-233851 (PSD-FL-206)

Dear Clair:

This letter is to inform you of recent updated information obtained for this project and to request changes to the Specific Conditions of the construction permit. The proposed changes are incorporated in a marked-up copy of the construction permit, which is included as an attachment to this letter. The updated information and requested changes are as follows:

1. Updated information to inform Florida Department of Environmental Protection (FDEP) that the combustion turbines will be equipped with a staged combustion technology dry low nitrogen oxides (NO_x) system only (a water injection system will not be installed prior to the dry low NO_x system).
2. Due to the expected date of available data from the manufacturer, change the date that the manufacturer's curves for the emission rate correction to other temperatures at different loads are due to FDEP from September 1, 1994 to January 1, 1995.
3. Addition of a Specific Condition to address meeting NO_x monitoring requirements using, as a substitute, the requirements of 40 CFR 75, Appendices A and B, provided the minimum criteria of 40 CFR 60 are met.
4. Clarification for determining compliance testing, particularly for NO_x emissions.

If you have any questions concerning this correspondence or would like to discuss the proposed revisions to the permit, please call me as soon as possible.

Sincerely,

Robert C. McCann for

Kennard F. Kosky, P.E.
President

KFK/lcb

cc: Thomas Donovan, Orange Cogeneration Limited Partnership
William Malenius, Ark Energy, Inc.
Kelly Spencer, Central and South West Services, Inc.
Willard Hanks, FDEP
File (2)

13019A1/14

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189
5405 West Cypress Street, Suite 215, Tampa, Florida 33607, 813-287-1717 FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910, FAX 407-994-9393
6821 Southpoint Drive North, Suite 216, Jacksonville, Florida 32216, 904-296-9663 FAX 904-296-0146
One Church Street, Suite 801, Rockville, Maryland 20850, 301-738-1100, FAX 301-738-1105

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

March 29, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E.
KBN Engineering and Applied Sciences, Inc.
1034 Northwest 57th Street
Gainesville, Florida 32605

Dear Mr. Kosky:

Re: Orange Cogeneration L.P.
AC 53-233851/Specific Condition No. 17

The following guidance is provided to clarify the issues raised in your March 11, 1994, letter on the referenced facility. The Department replaced the original tables in 2-2, 2-3, and 2-4 in the application with the October 28, 1993, revised tables. Until new combustion turbine manufacturer's curves are submitted to and approved by the Department, the maximum allowable emissions of the turbines will be based on the October 28, 1993, tables. Note that the combustion turbine air inlet temperature will be substituted for the ambient temperature in these tables to extrapolate the maximum allowable air pollutant emissions.

Please write to me if you need additional clarification on this matter.

Sincerely,

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

CHF/WH/bjb

cc: Bill Thomas, SWD
Linda Novak, PCESD
Thomas Donovan, Orange Cogen. L.P.

KBN

March 11, 1994

RECEIVED

MAR 14 1994

Bureau of
Air Regulation

Mr. Clair Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Orange Cogeneration Limited Partnership
Permit Application AC 53-233851 (PSD-FL-206)
Specific Condition No. 17

Dear Clair:

This correspondence presents our understanding of the Department's proposed revision to Specific Condition No. 17 of the referenced permit (see Department's letter of February 18, 1994 from Mr. Howard L. Rhodes, Director, Division of Air Resources Management, to Mr. Thomas F. Donovan, Orange Cogeneration Limited Partnership). Until new curves are approved by the Department or the combustion turbines meet the NO_x emission standards of 15 ppmvd corrected to 15 percent O_2 and ISO conditions (whichever occurs first), the stack, operating, and emission data for the proposed turbines presented in Revision 1 to Tables 2-2, 2-3, and 2-4 will be used (see attached tables). Please note that the ambient temperatures referenced in these tables refer to the air inlet temperature to the turbine. These tables, which were included in KBN's correspondence to the Department on October 29, 1993, included performance data for the turbines operating at a controlled air inlet temperature of 47°F and are the basis of the emission limits given in Tables 1 and 2 of the construction permit.

It is our understanding that KBN's correspondence of October 29, 1993 and October 28, 1993 (waiving time requirements) are included as part of the permit application (listed as attachments).

If you have any questions concerning this correspondence or this information does not agree with the proposed revisions to the permit, please call me as soon as possible.

Sincerely,

Robert C McCann for

Kennard F. Kosky, P.E.
President

cc: Mr. William Malenius, Ark Energy, Inc.
Mr. Thomas Donovan, Ark Energy, Inc.
Mr Ward Marshall, Central and South West Services, Inc.
Mr. Willard Hanks, FDEP
B. Thomas, SW Dist
J. Novak, PCESD

13019A1/11

Revision 1
Table 2-2. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Water Injection--Simple Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperatures (°F) at					
	20°F	40°F	47°F	59°F	80°F	100°F
Stack Data (ft)						
Height	60	60	60	60	60	60
Diameter	9.0	9.0	9.0	9.0	9.0	9.0
Operating Data						
Temperature (°F)	754	804	831	830	842	859
Velocity (ft/sec)	142.9	149.7	151.6	145.4	132.2	119.6
Maximum Hourly Emission Data (lb/hr) Per Unit[b]						
SO_2	1.07	1.13	1.17	1.09	0.95	0.82
PM	5.0	5.0	5.0	5.0	5.0	5.0
NO_x[c]	35.7	37.8	38.5	36.3	31.6	27.3
CO	28.5	28.4	27.8	26.8	24.1	21.3
VOC	4.07	4.05	3.98	3.83	3.44	3.04
Sulfuric Acid Mist	0.082	0.087	0.090	0.083	0.072	0.063
Annual Potential Emission Data (TPY) Per Unit[b]						
SO_2	NA	NA	5.1	4.76	NA	NA
PM	NA	NA	21.9	21.9	NA	NA
NO_x[c]	NA	NA	168.5	159.1	NA	NA
CO	NA	NA	122.0	117.5	NA	NA
VOC	NA	NA	17.4	16.8	NA	NA
Sulfuric Acid Mist	NA	NA	0.39	0.36	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-1 through A-4 provide information on the simple cycle operation with wet injection.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Revision 1
Table 2-3. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Water Injection--Combined Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperatures (°F) at					
	20°F	40°F	47°F	59°F	80°F	100°F
Stack Data (ft)						
Height	100	100	100	100	100	100
Diameter	8.5	8.5	11.0	8.5	8.5	8.5
Operating Data						
Temperature (°F)	215	215	230	215	215	215
Velocity (ft/sec)	89.1	89.6	54.2	85.3	76.8	68.6
Maximum Hourly Emission Data (lb/hr)[b]/Per Unit						
SO_2	1.07	1.13	1.17	1.09	0.95	0.82
PM	5.0	5.0	5.0	5.0	5.0	5.0
NO_x[c]	35.7	37.8	38.5	36.3	31.6	27.3
CO	28.5	28.4	27.8	26.8	24.1	21.3
VOC	4.07	4.05	3.98	3.83	3.44	3.04
Sulfuric Acid Mist	0.082	0.087	0.090	0.083	0.072	0.063
Annual Potential Emission Data (TPY)[b]/Per Unit						
SO_2	NA	NA	5.1	4.76	NA	NA
PM	NA	NA	21.9	21.9	NA	NA
NO_x[c]	NA	NA	168.5	159.1	NA	NA
CO	NA	NA	122.0	117.5	NA	NA
VOC	NA	NA	17.4	16.8	NA	NA
Sulfuric Acid Mist	NA	NA	0.39	0.36	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-5 through A-8 provide information on combined cycle operation with wet injection.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Revision 1

Table 2-4. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Dry Low NO_x Combustion Technology--Combined Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperatures (°F) at					
	20°F	40°F	47°F	59°F	80°F	100°F
Stack Data (ft)						
Height	100	100	100	100	100	100
Diameter	8.5	8.5	11.0	8.5	8.5	8.5
Operating Data						
Temperature (°F)	215	215	230	215	215	215
Velocity (ft/sec)	86.9	86.6	52.4	82.9	75.4	67.6
Maximum Hourly Emission Data (lb/hr) Per Unit[b]						
SO_2	1.03	1.08	1.11	1.03	0.91	0.79
PM	5.0	5.0	5.0	5.0	5.0	5.0
NO_x[c]	34.7	36.3	37.0	34.8	30.7	26.6
CO	28.6	28.4	27.8	27.0	24.3	21.5
VOC	4.09	4.05	3.98	3.86	3.47	3.06
Sulfuric Acid Mist	0.079	0.082	0.085	0.079	0.070	0.060
Annual Potential Emission Data (TPY) Per Unit[b]						
SO_2	NA	NA	4.87	4.51	NA	NA
PM	NA	NA	21.9	21.9	NA	NA
NO_x[c]	NA	NA	161.9	152.3	NA	NA
CO	NA	NA	121.9	118.2	NA	NA
VOC	NA	NA	17.4	16.9	NA	NA
Sulfuric Acid Mist	NA	NA	0.37	0.35	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-9 through A-12 provide information on combined cycle operation with dry low NO_x.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 18, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Thomas F. Donovan
Orange Cogeneration Limited Partnership
1901 Clear Springs Road
Bartow, Florida 33830

Dear Mr. Donovan:

Re: AC 53-233851

The Department acknowledges receipt of your February 3, 1994, letter responding to Specific Condition No. 17 of the referenced permit. You stated that two GE LM 6000 combustion turbines (CT) were selected for the proposed cogeneration facility on November 8, 1993, but that the manufacturer's emission rate correction curves at ambient temperatures for different operating loads will not be available until mid - 1994. We also note that the units for the nitrogen oxides emission standard in the construction permit are parts per million by volume corrected to 15 percent oxygen and ISO standard ambient conditions (ppmvd @ 15% O_2 ISO conditions). The units for this emission standard in GE's November 19, 1993, letter to Mr. Williams does not mention the ISO standard ambient condition correction. You may want to clarify this matter with GE.

In response to your letter, the Department is amending Specific Condition No. 17 of Permit No. AC 53-233851 as follows:

FROM:

Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of inlet air temperatures for the purpose of compliance determination. The maximum allowable emissions at different air inlet temperatures shall be based on the CT manufacturer's curve but shall not exceed the maximum rates listed in Tables 1 and 2, Allowable Emission Rates.

2-10-94
Told Barr McCann, KBN, tables referred to are revision that included 47°F operating temp and are consistent with tables in permit
wna

TO:

Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review by September 1, 1994. Until new curves are approved by the Department or the combustion turbines meet the NO_X emission standard of 15 ppmvd @ 15% ISO conditions (whichever occurs first), the stack, operating, and emission data for the proposed combustion turbines in Tables 2-2, 2-3, and 2-4 of the application will be used. The data will be used to determine compliance with the maximum allowable emission rates of the regulated air pollutants at different air inlet temperatures for these turbines.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the applicant of the amendment request/application and the parties listed below must be filed within 14 days of receipt of this amendment. Petitions filed by other persons must be filed within 14 days of the amendment issuance or within 14 days of their receipt of this amendment, whichever occurs first. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information:

(a) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action;

(g) A statement of the relief sought by petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this amendment. Persons whose substantial interests will be affected by any decision of the Department with regard to the request/application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this amendment in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

A copy of this letter must be filed with Permit No. AC 53-233851 and shall become a condition of that permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/WH/bjb

Attachment: Orange Cogeneration February 3, 1994 letter

cc: Bill Thomas, SWD
Linda Novak, PCESD
K. Kosky, KBN

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this AMENDMENT and all copies were mailed by certified mail before the close of business on 2/23/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to 120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell 2/23/94
Clerk Date

Memorandum

Florida Department of
Environmental Protection

CLAIR

TO: Howard L. Rhodes

FROM: Clair H. Fancy

DATE: February 18, 1994

SUBJ: Amendment of Permit
Orange Cogeneration L.P.

Attached for your approval and signature is a letter that will amend the construction permit for a natural gas fired cogeneration facility that is under construction in Bartow, Polk County, Florida. The amendment will allow additional time for the permittee to update the performance curves for the combustion turbines.

I recommend your approval and signature.

CHF/WH/bjb

Attachment

ORANGE COGENERATION

Project Office: 1901 Clear Springs Road
Bartow, FL 33830
(813)-533-3399
Facsimile: (813)-533-4152

February 3, 1994

RECEIVED
FEB 07 1994
Bureau of
Air Regulation

Clair Fancy, Chief
Bureau of Air Resource Management
Department of Environmental Protection
2600 Blair Stone Road
Talahassee, FL 32399

Re: Orange Cogeneration Project
FDEP Permit No. AC53-233851

Dear Mr. Fancy:

Pursuant to Specific Condition No. 17 of the above referenced permit, Orange Cogeneration LP, as the Permittee, is required to submit for the Department's review the combustion turbine manufacturer's emission rate correction curves at ambient temperatures for different operating loads. These curves are to be submitted within 90 days of the selection of the combustion turbines.

On November 8, 1993, the Project contractually confirmed its selection of two LM6000 combustion turbines (CT's) with the General Electric Company. General Electric has guaranteed the Project that between 1995 and 1997 the CT's, equipped with dry low-NOx (DLN) combustors, will achieve the proscribed NOx emission rates of 25 ppmvd at all the expected operational conditions (60 to 100% load). Thus, there are no correction curves needed during that period through 1997.

General Electric has also guaranteed that beginning January 1, 1998 the CT's will meet the 15 ppmvd NOx emission limit established in the permit at full load. However, General Electric has advised that is has not tested the LM6000 with DLN combustors at partial load circumstances, but currently plans to do so in Spring, 1994. The Project does not expect to have the correction data for 1998 available from General Electric until mid-1994. Upon receipt, those curves will be submitted to DEP for review consistent with Condition 17. Attached are General Electric's letters on this subject.

We believe the above meets the Permittee's requirements under Specific Condition No. 17. Please feel free to contact me with any questions or need for additional information at the Project's office in Bartow. The address and phone numbers are listed above.

Very truly yours,

Orange Cogeneration Limited Partnership

Thomas F. Donovan

Thomas F. Donovan
Program Manager

cc: Ward Marshall
Doug Roberts
Bill Malenius

Memorandum

Florida Department of
Environmental Protection

TO: Orange Cogeneration Permit File (PSD-FL-206)

THRU: Preston Lewis Preston
John Brown JB

105 GRANT WORK PLAN COMMITMENTS

FROM: Cleve Holladay

DATE: January 25, 1994

SUBJECT: Stack Height Remand Impact on Orange Cogen Permits Issued December 30, 1993

The permits for the Orange Cogeneration Limited Partnership's 103 megawatt cogeneration facility (AC53-233851, AC53-233852, PSD-FL-206) were issued on December 30, 1993. The stack height remand memo from Clair Fancy to the air permitting meteorologists was signed on January 19, 1994--after these permits were issued. This memo contains suggested caveat language which is to be included in all PSD NSR permits issued by the Department in fiscal year 1994. As suggested in a memo to the department from EPA discussing the stack height remand, the use of this caveat language in all PSD permits eliminates the need for the department to determine stack height remand applicability for every PSD permit issued. This determination is not always straightforward. Since the Orange Cogeneration permits are the only ones issued before this stack height remand memo was signed, I have specifically reviewed them and have determined that they are not impacted by the stack height remand. Therefore, I suggest that no amendment to these permits is necessary.

BEST AVAILABLE COPY

GE Power Generation

Production Systems Engineering
General Electric Company
One River Road, 53-401, Schenectady, NY 12345 USA
(518) 385-7964, Fx: (518) 385-1474, Tx: 145354

January 21. 1994

COPY

Mr. Thomas Donavan
Orange Cogeneration
c/o Ark Energy
23046 Avenida Dela Carlota
Laguna Hills, CA 92653
(fax (813)-533-0144)

Subject: Orange Cogen

Dear Mr. Donavan:

In response to your telephone conversation with Len Kaplan, testing to the first DLE LM6000 is currently scheduled to occur between mid March and mid May, 1994. We expect to have valid emissions data from this test by early May, 1994.

Please advise if you have any questions or require additional information.

Best regards,

John Sanders

John B. Sanders
LM6000 Technical Leader

Copies to-

J. Drummond,	Zurn/NEPCO. Portland, ME
Gary Gross,	S&S, Jacintoport, Houston, TX
C. Shook,	S&S, Houston, TX
R. Gentner,	2-4E
L. Kaplan,	23-221

John
~~Preston~~
Patty-file

ORANGE COGENERATION LIMITED PARTNERSHIP
23046 Avenida de la Carlota, Suite 200
Laguna Hills, CA 92653
714-588-3767

COPY

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED
JAN 21 1994
Bureau of
Air Regulation

January 17, 1994

Southwest District Office
State of Florida
Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation
3804 Coconut Palm Drive
Tampa, FL 33619-8318

Orange Cogen

Subject: Permit Number: AC53-233851
Two Combustion Turbines

The Permittee hereby notifies the Department that construction of the permanent facility for the above referenced Permit commenced January 10, 1994.

Construction of the Auxiliary Boiler under Permit Number AC53-233852 has not yet commenced. The Project may be contacted at 714-588-3767 if there are any questions.

Very truly yours,

Orange Cogeneration Limited Partnership

Thomas F. Donovan

Thomas F. Donovan
Program Manager

cc: Bill Malenius
C. H. Fancy
D. Roberts
W. Marshall

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

JAN 10 1994

4APT-AEB

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

SUBJ: Orange Cogeneration Limited Partnership (PSD-FL-206)

Dear Mr. Fancy:

As requested in your letter dated November 12, 1993, we have reviewed your preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced source. The proposed source will consist of a 103 MW cogeneration facility including two biogas/natural gas-fired combustion turbines, two unfired heat recovery steam generators, and one auxiliary boiler.

Your BACT determination consists of the use of dry low-NO_x combustors on the turbines and low-NO_x burners on the boiler for the control of NO_x emissions, use of clean fuels for the control of PM and SO_2 emissions, and good combustion practices for the control of VOC and CO emissions. We have no adverse comments on your determination.

Thank you for the opportunity to review and comment on this package. If you have any questions on these comments, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

CC: A. Hanks
K. Zhang
B. Thomas, SW Dist.
J. Bunyak, NPS
J. Rual, Polk Co.
K. Kosky, P.E., KBN

Florida Department of
Environmental Protection

Memorandum

TO: Virginia B. Wetherell

for FROM: Howard L. Rhodes

DATE: December 29, 1993

SUBJECT: Approval of a Construction Permit
Orange Cogeneration Limited Partnership

Attached for your approval and signature are air construction permits and a Best Available Control Technology for a 103 megawatt cogeneration facility to be built for Orange Cogeneration Limited Partnership in Bartow, Polk County, Florida.

The public did not object to the issuance of these permits.

I recommend your approval and signature.

HLR/WH/bjb

Attachment

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DEP File No. **AC** 53-233851
AC 53-233852
PSD-FL-206
Polk County

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Laguna Hills, CA 92653
______________________________/

Enclosed are Permit Numbers **AC** 53-233851 and **AC** 53-233852 (PSD-FL-206) for the construction of a natural gas/equivalent biogas fired 103 megawatt cogeneration facility to be located near Orange-Co. of Florida, Inc. on Clear Spring Road in Bartow, Polk County, Florida. These permits are issued pursuant to Section 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 12/30/93 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell 12/30/93
(Clerk) (Date)

Copies furnished to:
B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
L. Novak, PCESD
K. Kosky, KBN

Final Determination

Orange Cogeneration Limited Partnership
Bartow, Florida
Polk County

Two Combustion Turbines
One Auxiliary Boiler

Permit No. AC53-233851
AC53-233852
PSD-FL-206

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

December 29, 1993

Final Determination

The Technical Evaluation and Preliminary Determination for the permits to construct a 103 megawatt cogeneration facility containing two gas combustion turbines and one auxiliary boiler in Bartow, Polk County, Florida, was distributed on November 18, 1993. The Notice of Intent to Issue was published in the Tampa Tribune on November 20, 1993. Copies of the evaluation were available for public inspection at the Department offices in Tampa and Tallahassee.

Comments on the evaluation and proposed permits were submitted by the National Park Service (NPS) and the applicant. The National Park Service stated that the Federal Land Manager had determined that the potential for the proposed sources to have a significant impact on the air quality related values (AQRVs) of the Chassahowitzka Wilderness Area was low. The NPS also asked that Specific Condition No. 13 of the permit for the combustion turbines (CTs) (AC 53-233851) be revised to require the use of a selective catalytic reduction system (SCR) if the turbine's nitrogen oxide (NO_x) emissions exceeded 15 ppmvd @ 15% O_2, ISO conditions, and that the NO_x emission standard be lowered if it is determined that a lower NO_x emission rate is achievable by a SCR. After consideration of this request, the Department has revised Specific Condition No. 13 to require the applicant to meet the limit that is in the permit, by installing any additional control equipment that may be required.

The applicant noted that several of the emission rates listed in the evaluation were incorrect (not based on the inlet air temperature at which the CTs will operate) and requested permission to use additional EPA approved stack test methods to show compliance with the emissions limits in the permits. In response to their comments, the following changes have been made.

In Table 2, Allowable Emission Rates for each combustion turbine, the volatile organic compound (VOC) emissions for dry low NO_x (DLN) control are reduced from 19.8 to 16.9 TPY and the carbon monoxide (CO) emissions from 161.9 to 127.0 TPY. In the Best Available Control Technology determination, the carbon monoxide emissions from two CTs are reduced from 57.2 lbs/hr and 343.9 TPY to 55.6 lbs/hr and 243.9 TPY, respectively. The volatile organic compound emissions are reduced from 8.17 to 7.96 lbs/hr.

The following stack test methods are added to the permits.

EPA Method 17 for PM/PM_{10} provided the stack temperature is less than 320°F.
EPA Method 18 and 25A for VOC.
EPA Method 202 for condensable particulate matter (PM).

The final action of the Department will be to issue the permits as proposed in the Technical Evaluation and Preliminary Determination except for the changes noted above.

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233851
PSD-FL-206
Expiration Date: April 1, 1998
County: Polk
Latitude/Longitude: 27°52'15"N 81°49'31"W
Project: Two Combustion Turbines

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of two natural gas/equivalent biogas fired GE LM 6000 (or equivalent) combustion turbines (CT), two heat recovery steam generators, one steam turbine and, being permitted separately, an auxiliary boiler (AC53-233852). The CTs will be initially equipped with either a water injection system or a dry low NO_x system to control nitrogen oxides (NO_x) emission. The water injection system, if installed, will be replaced with dry low NO_x combustion technology by December 31, 1995. Each CT will be equipped with a 100 ft. high, 11 ft. diameter stack that will handle approximately 300,000 actual cubic feet per minute of flue gas at 230°F. The cogeneration facility will be located on Clear Springs Road, Bartow, Polk County, Florida 33830.

The UTM coordinates of this facility are Zone 17, 418.75 kmE and 3083.0 kmN.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Application received July 1, 1993
2. DEP July 22, 1993, letter
3. KBN August 5, 1993, letter
4. KBN August 29, 1993, letter
5. Tables 1 and 2, Allowable Emission Rates

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. A description of and cause of non-compliance; and

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

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

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

GENERAL CONDITIONS:

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    (X) Determination of Best Available Control Technology (BACT)
    (X) Determination of Prevention of Significant Deterioration (PSD)
    (X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

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

SPECIFIC CONDITIONS:

Construction Requirements

1. Water/steam injection systems or dry low NO_X systems shall be installed and operated on each combustion turbine (CT). If a water/steam injection system is initially installed, it will be replaced by dry low NO_X combustion technology.

2. Dry low NO_X combustion technology shall be installed and in operation on the CTs prior to December 31, 1995.

3. A system, accurate to within 5 percent, to continuously monitor the fuel consumption and the ratio of water/steam to fuel being fired shall be installed on each CT.

4. The heat recovery steam generator (HRSG) installed on each CT shall not be equipped with an auxiliary/duct burner.

5. Each CT stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, and electrical power) that meet the specifications given in F.A.C. Rule 17-297.345.

Operation Limitations

6. The CTs shall comply with all requirements of 40 CFR 60, Subpart GG (July, 1993), Standard of Performance for Stationary Gas Turbines, which is adopted by reference in F.A.C. Rule 17-296.800(2)(a).

SPECIFIC CONDITIONS:

7. The facility is allowed to operate continuously, 8760 hours per year.

8. Only natural gas/equivalent biogas fuel shall be used for fuel at this facility.

9. Each CT shall have a maximum heat input based on the lower heating value (LHV) of the fuel of 388 million British thermal units per hour (MMBtu/hr), which is approximately 409,900 cubic feet per hour (CFH) of natural gas, when using water/steam injection to control nitrogen oxides (NO_x) emission.

10. Each CT shall have a maximum heat input (LHV) of 368.3 MMBtu/hr, which is approximately 389,300 CFH of natural gas, when using dry low NO_x technology to control NO_x emissions.

11. The operation of this facility shall not create a nuisance or discharge air pollutants that cause or contribute to objectionable odors.

Emission Limitation

12. Prior to January 1, 1998, the maximum NO_x concentration, 1 hour average, from each CT/HRSG unit shall not exceed 25 parts per million by volume dry corrected to 15 percent oxygen and ISO standard ambient conditions (ppmvd @ 15% O_2 ISO conditions), as determined by the procedures in Specific Conditions No. 18 and 19.

13. After December 31, 1997, the maximum NO_x concentration, 1-hour average, from each CT/HRSG unit shall not exceed 15 ppmvd @ 15% O_2 ISO conditions as determined by the procedure in Specific Conditions Nos. 18 and 19. Should 15 ppmvd NO_x @ 15% O_2 ISO conditions not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard. The permittee shall obtain prior approval from the Department for any air pollution control equipment not addressed in this permit that is needed to meet the NO_x emission standard.

14. The maximum emission rates for particulate matter (PM/PM_{10}), volatile organic compounds (VOC), NO_x, and carbon monoxide (CO) shall not exceed any of the rates listed in Tables 1 and 2, Allowable Emission Rates. Allowable emissions shall be extrapolated between the temperatures listed in the CT manufacturer's curve for emission rates of different air inlet temperatures.

15. Visible emissions shall not exceed 10 percent opacity, 6 minute average.

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851 (PSD-FL-206)
42 MW SIMPLE CYCLE GAS TURBINE

Table 1 - Allowable Emission Rates for each Combustion Turbine

		Allowable Emissions Standards/Limitations				
		~~ISO~~ Conditions[b]		Maximum Corrected[c]		Basis for
Pollutant[a]	Basis	lb/hr	TPY	lb/hr	TPY	Limit
NO_x	25 ppmvd[d] at 15% O_2/ISO	36.3	159.1	38.5	168.5	BACT
CO	30 ppmvd	26.8	117.5	27.8	122.0	BACT
PM/PM_{10}	0.0139 lb/MMBtu	5	21.9	5	21.9	BACT
VOC	10 ppmvd	3.83	16.8	3.98	17.4	BACT

a Pollutant emissions are based on 8,760 hours per year operation firing natural gas or equivalent biogas at 59° F.

b Emissions rates are based on 100% load and at ISO conditions. Pollutant emission rates may vary depending on the air inlet temperature to the combustion turbine (CT) and CT characteristics. Manufacturer's curves for the emission rate corrections to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination.

c Maximum emission rates not to be exceeded after correction for air inlet temperature to the combustion turbine.

d The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 at ISO conditions by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with a compliance plan that will ensure compliance within a time period approved by the Department. NO_x emission concentrations are to be corrected to ISO conditions to demonstrate compliance with the NO_x emissions standard.

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851 (PSD-FL-206)
42 MW COMBINED CYCLE GAS TURBINE

Table 2 - Allowable Emission Rates for each Combustion Turbine

			Allowable Emissions Standards/Limitations				
			ISO Conditions[b]		Maximum Corrected[c]		Basis for
Pollutant[a]	Control[e]	Basis	lb/hr	TPY	lb/hr	TPY	Limit
NO_x	WI	25 ppmvd[d] at 15% O_2/ISO	36.3	159.1	38.5	168.5	BACT
	DLN	25 ppmvd at 15% O_2/ISO	34.8	152.3	37.0	161.9	BACT
CO	WI	30 ppmvd	26.8	117.5	27.8	122.0	BACT
	DLN	30 ppmvd	27	118.2	27.8	127.0	BACT
PM/PM_{10}	WI	0.0139 lb/MMBtu	5	21.9	5	21.9	BACT
	DLN	0.0147 lb/MMBtu	5	21.9	5	21.9	BACT
VOC	WI	10 ppmvd	3.83	16.8	3.98	17.4	BACT
	DLN	10 ppmvd	3.86	16.9	3.98	17.4	BACT

[a] Pollutant emissions are based on 8,760 hours per year operation firing natural gas or equivalent biogas at 59° F.

[b] Emissions rates are based on 100% load and at ISO conditions. Pollutant emission rates may vary depending on the air inlet temperature to the combustion turbine (CT) and CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination.

[c] Maximum emission rates not to be exceeded after correction for air inlet temperature to the combustion turbine.

[d] The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 at ISO conditions by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with a compliance plan that will ensure compliance within a time period approved by the Department. NO_x emission concentrations are to be corrected to ISO conditions to demonstrate compliance with the NO_x emissions standard.

[e] Wet injection (WI) and Dry Low-NO_x (DLN) combustors.

SPECIFIC CONDITIONS:

16. The emission rates for sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4), listed in the following table, shall be used for inventory purposes only.

Maximum Emission Rates for Each Combustion Turbine
for inventory purposes or PSD tracking

Pollutant	Combustion Turbine Water Injection		Combustion Turbine Dry Low NO_x Combustion	
	lb/hr	TPY	lb/hr	TPY
SO_2	1.17	5.1	1.11	4.87
H_2SO_4	0.09	0.39	0.085	0.37

17. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of inlet air temperatures for the purpose of compliance determination. The maximum allowable emissions at different air inlet temperatures shall be based on the CT manufacturer's curve but shall not exceed the maximum rates listed in Tables 1 and 2, Allowable Emission Rates.

Compliance Determination

18. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of rated capacity at the test ambient air temperature. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Compliance with the visible emissions, NO_x, SO_2, CO, PM/PM_{10}, and VOC emission standards shall be determined within 60 days of achieving maximum production but not later than 180 days after initial firing of each CT (40 CFR 60.8). Compliance with the visible emission, NO_x, and SO_2 standards shall be determined annually thereafter. The tests shall be conducted initially when the CTs are using water/steam system and again when dry low-NO_x technology is employed. Tests shall be conducted on both natural gas and biogas fuels.

SPECIFIC CONDITIONS:

19. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

EPA Method	Pollutant
5, 17*, or 201A and 202	PM/PM_{10}
9	Visible Emissions
10	CO
20	NO_x and SO_2
18, 25, or 25A	VOC

Other test methods may be used for compliance testing after prior Department approval.

*Stack flue gas temperature must be less than 320°F to use Method 17.

Administrative Requirement

20. Prior to January 1, 1998, the permittee shall provide a report showing how the allowable NO_x emissions of 15 ppmvd @ 15% O_2 ISO conditions is achieved by the CTs.

21. The permittee shall provide the Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction
- Anticipated date of initial starting 30 to 60 days prior to startup
- Actual date of startup up within 15 days after the starting
- Notification of the date of the compliance tests not less than 30 days prior to the test

22. Pursuant to F.A.C. Rule 17-210.300(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, and air emissions. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

23. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

SPECIFIC CONDITIONS:

24. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

David H Thorp for

Virginia B. Wetherell, Secretary

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

Permit Number: AC53-233852
PSD-FL-206
Expiration Date: April 1, 1996
Latitude/Longitude: 27°52'15"N
81°49'31"W
Project: Auxiliary Boiler
County: Polk

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto and specifically described as follows:

Installation of a 100 million British thermal unit per hour (MMBtu/hr) natural gas/equivalent biogas fired tube boiler equipped with a 65 foot high, 3.67 foot diameter stack designed to produce approximately 83,000 pounds per hour of saturated steam at 205 pounds per square inch gauge (psig) pressure. The heat input is based on the High Heating Value (HHV) of the fuel. The auxiliary boiler will be located on Clear Springs Road, Bartow, Polk County, Florida 33830.

The UTM coordinates of this facility are Zone 17, 418.75 kmE and 3083.0 kmN.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. Application received July 1, 1993
2. DEP July 22, 1993, letter
3. KBN August 5, 1993, letter

GENERAL CONDITIONS:

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

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

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

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

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

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

GENERAL CONDITIONS:

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

   a. Have access to and copy any records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

   a. A description of and cause of non-compliance; and

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

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

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

GENERAL CONDITIONS:

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    (X) Determination of Best Available Control Technology (BACT)
    (X) Determination of Prevention of Significant Deterioration (PSD)
    (X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

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

SPECIFIC CONDITIONS:

Construction Requirements

1. The auxiliary boiler shall be equipped with low-NO_X burners.

2. The boiler stack shall be equipped with stack sampling facilities (sample ports, work platforms, access, electrical power) that meet the specifications given in F.A.C. Rule 17-297.345.

Operation Limitations

3. The auxiliary boiler shall comply with all applicable requirements of 40 CFR 60, Subpart Dc.

4. The boiler is allowed to operate continuously, 8760 hours per year.

5. Only natural gas/equivalent biogas fuel shall be burned in this boiler.

6. The maximum heat input to the boiler based on the high heating value (HHV) of the fuel shall not exceed 100 MMBtu/hr which is the heat content of approximately 105,700 cubic feet of natural gas per hour.

7. The maximum allowable sulfur content (total) of the natural gas/biogas burned in the boiler shall not exceed 1 grain per 100 cubic feet (1 gr/100 CF) of gas.

SPECIFIC CONDITIONS:

8. The operation of this boiler shall not emit air pollutants that cause or contribute to objectionable odors.

9. Visible emissions shall not exceed 15 percent opacity.

10. Emissions from the boiler shall not exceed any of the following limits:

Pollutant	lbs/MMBtu	lbs/hr	TPY
NO_x	0.13	13.0	56.9
CO	0.10	10.0	43.8
VOC	0.04	4.3	18.8

11. Sulfur dioxide (SO_2) emissions from the boiler shall not exceed 0.003 lbs/MMBtu, 0.30 lbs/hr, and 1.3 TPY. An analysis of the fuel showing the sulfur content does not exceed 1 grain of total sulfur per 100 cubic feet of gas will be accepted as proof of compliance with the sulfur dioxide emission limit. Total sulfur content of the gas shall be determined by test method ASTM D 1072-80 (40 CFR 60.17 (July, 1993)).

12. Particulate matter (PM/PM_{10}) emissions from the boiler shall not exceed 0.01 lbs/MMBtu, 1.0 lbs/hr, and 4.4 TPY. No PM/PM_{10} stack test that is required if the visible emissions are less than 15 percent opacity.

Testing Requirements

13. Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90-100% of rated capacity. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Compliance with the visible emissions, NO_x, CO, and VOC emission standards shall be determined within 60 days of achieving maximum production but not later than 180 days after initial firing of the boiler. Compliance with the visible emissions and NO_x standards shall be determined annually thereafter.

SPECIFIC CONDITIONS:

14. Compliance shall be determined by the following test methods listed in 40 CFR 60, Appendix A (July, 1993).

EPA Method	Pollutant
9	Visible Emissions
10	CO
7E	NO_x
18, 25, or 25A	VOC

Other test methods may be used for compliance testing after prior Department approval.

15. The permittee shall provide the Southwest District office with the following notifications required by 40 CFR 60.7:

- When construction commenced within 30 days of commencement of construction.
- Anticipated date of initial startup, 30 to 60 days prior to startup.
- Actual date of startup within 15 days after the startup.
- Notification of the date of the compliance tests not less than 30 days prior to the tests.

16. Pursuant to F.A.C. Rule 17-210.300(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emission limits, etc. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

17. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

18. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate

SPECIFIC CONDITIONS:

application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Dand H Thy for

Virginia B. Wetherell, Secretary

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. William R. Malenius
Director of Project Development
Orange Cogeneration LP
23406 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

4a. Article Number
P 872 562 597

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

7. Date of Delivery 2-7-94

5. Signature (Addressee) [signature]

6. Signature (Agent)

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

Thank you for using Return Receipt Service.

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

P 872 562 597

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. 23046 Avenida De La CSrlota	
P.O., State and ZIP Code Laguna Hills, CA 92653 Ste 400	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 2-1-94 Permit: AC 53-233851 AC 53-233852 PSD-FL-206	

PS Form **3800**, JUNE 1991

P 872 562 592

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. Orange Cogeneratio 23046 Avenida De La Carlota	
P.O., State and ZIP Code Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 12-30-93 Permit: AC 53-233851 -852 PSD-FL-206	

PS Form **3800**, JUNE 1991

P 872 562 594

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. 3753 Howard Hughes Pkwy, Ste 200	
P.O., State and ZIP Code Las Vegas, NV 89109	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 1-19-94 Permit: AC53-233851, -52 PSD-FL-206	

PS Form **3800**, JUNE 1991

BEST AVAILABLE COPY

330202

12/30/93

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

CERTIFIED MAIL

P 872 562 592

RETURN TO SENDER

ATTEMPTED NOT KNOWN
NO SUCH NUMBER
INSUFFICIENT ADDRESS
FORWARDING ORDER EXPIRED
VACANT
DECEASED
NO MAIL RECEPTACLE
REFUSED
ROUTE NO. 540 DATE 1-3-94
CARR/INITIALS

DEC 30 '93

23046
Avenida
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Director of Project Development
Orange Cogeneration Limited Partnership
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Laguna Hills, CA 92653

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Best Available Control Technology (BACT) Determination
Orange Cogeneration Limited Partnership
Polk County
AC53-233851, **AC**53-233852, PSD-FL-206

The applicant proposes to construct a 103 gross megawatt (MW) natural gas/equivalent biogas fired cogeneration facility in Bartow, Polk County, Florida. Major components of the cogeneration facility are: two combustion turbines (CT), each with a heat recovery steam generator (HRSG), an auxiliary boiler, steam turbine generator, and associated equipment. Both CTs will consume up to 776 million British thermal units per hour (MMBtu/hr) of gas fuel based on the lower heating value (LHV) of the fuel and produce 78 MW of electricity. The HRSGs, which do not use supplemental fuel, produce approximately 100,000 lbs/hr of steam that can generate 25 MW of electricity. The fire-tube auxiliary boiler consumes 100 MMBtu/hr of gas fuel and produces approximately 83,000 lbs/hr of steam.

The following table lists the estimated maximum emissions from the cogeneration facility.

	Two CTs		Auxiliary Boiler	
Pollutant	lbs/hr	TPY	lbs/hr	TPY
Sulfur dioxide (SO_2)	2.34	10.3	0.3	1.3
Particulate Matter (PM/PM_{10})	10	43.8	1.0	4.4
Nitrogen Oxide (NO_x)	77.0	336.9	13.0	56.9
Carbon Monoxide (CO)	55.6	243.9	10.0	43.8
Volatile Organic Compounds (VOC)	7.96	34.9	4.3	18.8
Sulfuric Acid Mist	0.18	0.79	0.023	0.1

The cogeneration facility requires a BACT determination for NO_x, CO, PM, and VOC. In addition, the auxiliary boiler requires a BACT determination for SO_2.

Date of Receipt of a BACT Application

July 1, 1993

BACT Requested by the Applicant

Pollutant	Proposed Limit	Air Pollution Control
Combustion Turbine		
PM	0.01 gr/scf*	Clean Fuel (gas)
NO_x	25 ppmvd @ 15%**	Wet Injection (WI) or
	15 ppmvd @ 15%**	Dry Low-NO_x Combustors

CO	30 ppmvd	Combustion Controls
VOC	10 ppmvd	Combustion Controls

Auxiliary Boiler

PM	0.01 lbs/MMBtu	Clean Fuel (gas)
NO_X	0.13 lbs/MMBtu	Low-NO_X burners
SO_2	1 grain/100CF natural gas	Clean Fuel (natural gas)
CO	0.10 lbs/MMBtu	Combustion Control
VOC	0.043 lbs/MMBtu	Combustion Control

*grains per standard cubic foot
**parts per million by volume dry at 15 percent oxygen and ISO conditions
Applicant is committed to meeting 15 ppmvd @ 15% O_2 and ISO conditions with dry low-NO_X combustors after December 31, 1997.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212, 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, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from cogeneration facilities 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 matter). 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.

Although all of the pollutants addressed in the BACT analysis may be subjected 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, 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.

<u>BACT Pollutant Analysis for Combustion Turbines (CT)</u>

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 control technologies evaluated were selective catalytic reduction (SCR), wet injection (WI), dry low-NO_x combustor, NO_xOUT process, thermal DeNO_x, and selective noncatalytic reduction (SNCR).

NO_xOUT (urea with catalyst), thermal DeNO_x (ammonia with catalyst), and selective noncatalytic reduction system (ammonia without catalyst) to reduce NO_x emissions from the CT were not feasible because of process constraints (flue gas temperature too low and oxygen content too high).

SCR, dry low-NO_x combustor technology, and wet injection controls were considered feasible.

The applicant has stated that BACT for nitrogen oxides will be met initially by using water/steam injection or advanced combustor design to limit emissions to 25 ppmvd 15% O_2 and ISO conditions when burning natural gas/equivalent biogas. After December 31, 1995, dry low NO_x combustion will be used to meet the same NO_x emission limit of 25 ppmvd @ 15% O_2 and ISO conditions. After December 31, 1997, a limit of 15 ppmvd @ 15% O_2 and ISO conditions will be met. Should 15 ppmvd NO_x @ 15% O_2 and ISO conditions not be achieved during the initial compliance tests, the permittee will provide the Department with a plan and schedule to meet this standard.

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 SCR system.

SCR 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 though the catalyst bed. With a new catalyst the SCR process can achieve up to 90% reduction of NO_x. As the catalyst ages, the maximum NO_x reduction will decrease.

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.

Although technically feasible, the applicant has 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 (spent 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) The energy impacts of SCR will reduce potential electrical power generation by 0.8 percent.
f) Incremental cost effectiveness for the application of SCR technology to the Orange Cogeneration L.P. project was considered to be $7,970 when emissions are at 25 ppm and $23,510 when emissions are at 15 ppm. Since SCR has been determined to be BACT for gas turbines, 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 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."

The cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR.

A concern associated with the use of SCR on combustion turbines 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 in some previous BACT determinations. This salt also increases particulate matter (PM/PM_{10}) emissions.

For natural gas/equivalent biogas 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. 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 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 on two CTs for this project at 100 percent capacity factor and burning natural gas/equivalent biogas is $1,648,000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

Initially, NO_x emissions will be 25 ppmvd @ 15% O_2 and ISO conditions. Emissions will be 318 TPY NO_x with WI. When dry-low NO_x controls are installed, NO_x emissions will be 305 TPY. After the combustion turbines meet the NO_x emissions standard of 15 ppmvd @ 15% O_2 and ISO conditions, NO_x emissions will be 191 TPY. A SCR would reduce the NO_x emissions by 207 TPY during the first 2 years of operation when the CTs emit 25 ppmvd @ 15% O_2 and ISO conditions. Thereafter, when dry-low NO_x controls are used, a SCR would reduce NO_x emissions by 120 TPY. When these reductions are taken into consideration, the total cost with SCR is $21,900 per ton of NO_x removed. This calculated cost is higher than has previously been approved as BACT.

A review of the latest Department BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for gas turbines. Most combustion turbine manufacturers are 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, this technology will likely be available by 1998.

BACT Determination for NO_x for the CT's by Department

NO_x Control

The information that the applicant presented and Department calculation indicate that the cost per ton of controlling NO_x for this turbine [$21,900 per ton] 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 combustion turbine 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/steam 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 combustion turbine manufacturers are developing programs 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.

Based on this, the Department has determined to revise and lower the allowable BACT limit for this project to 15 ppmvd at 15% O_2 no later than 1/1/98.

Carbon Monoxide (CO)

CO emissions are caused by incomplete combustion of the fossil fuel. The applicant investigated the use of combustion control and catalytic oxidation to control CO emission. With combustion control, CO emissions would be 30 ppmvd (236 TPY). With catalytic oxidation, CO emissions would be 10 ppmvd (78 TPY). The annualized cost of the catalyst system is $834,700 or $5,280 per ton of CO removed.

BACT Determination for CO for the CT's by Department

Because catalytic oxidation would increase operation cost by $5,280 per ton of CO removed, and have no significant reduction in ambient air quality, the Department accepts an emission limit for CO of 30 ppmvd obtained through combustion control as BACT for these CTs.

Volatile Organic Compounds (VOC)

VOC emissions are caused by incomplete combustion of fossil fuel. The applicant proposes to meet an emission limit of 10 ppmvd through the use of clean fuel (natural gas) and combustion controls. This is similar to the BACT applied to other sources.

BACT Determinations for VOC for the CTs by Department

The Department accepts an emission limit for VOC of 10 ppmvd obtained through the use of clean fuel (natural gas) and combustion control as BACT for these CTs.

Particulate Matter (PM/PM_{10})

PM emissions are caused by incomplete combustion and traces of solids in the fuel. Proper combustion of clean fuel will emit only trace amounts of PM/PM_{10}. Each proposed CT will emit 5 lbs/hr of PM/PM_{10} or about 0.01 grains per standard cubic foot (gr/dscf). This is similar to the PM/PM_{10} emissions that can be met with the best air pollution control device, a baghouse.

BACT Determination for PM/PM_{10} for the CTs by Department

The Department accepts an emission limit for PM/PM_{10} of 5 lbs/hr and 10 percent opacity as BACT for each CT.

BACT Pollutant Analysis for the Auxiliary Boiler

Nitrogen Oxides (NO_x)

Nitrogen oxide emissions from boilers can be controlled by selective catalytic reduction (SCR), flue gas recirculation (FGR), and low-NO_x combustors.

The applicant proposes to meet a NO_x emission limit of 0.13 lbs/MMBtu through the use of low-NO_x combustors. This emission limit is below the new source performance standard for large boilers. The cost of using SCR or FGR would exceed $5,000 per ton NO_x removed.

BACT Determined for NO_x for the Boiler by Department

The Department accepts an emission limit for NO_x of 0.13 lbs/MMBtu as BACT for this boiler.

Particulate Matter (PM/PM_{10}), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC)

PM/PM_{10}, CO and VOC are the products of incomplete combustion of fossil fuel. The applicant proposes to meet emission limits of 0.01 lbs PM/MMBtu, 0.10 lbs CO/MMBtu, 0.04 lbs VOC/MMBtu through the use of clean fuel (natural gas/equivalent biogas) and combustion control. Visible emissions shall not exceed 15 percent opacity.

BACT Determination for PM, CO, and VOC for the Boiler by Department

The Department accepts the use of clean fuel (natural gas/equivalent biogas) and combustion controls to meet the proposed emission limits for PM/PM_{10}, CO, and VOC as BACT for this boiler.

Sulfur Dioxide (SO_2)

Sulfur dioxide emissions are caused by the oxidation of sulfur in the fuel. Natural gas/equivalent biogas contains only trace amounts of sulfur - 1 grain per 100 cubic feet (gr/100 CF). This will result in an estimated sulfur dioxide emission of 0.30 lbs/hr. Cleaner fuel is not available and add on controls for SO_2 are not justified at this low emission rate.

BACT Determination for SO_2 for the Boiler by Department

Natural gas/equivalent biogas fuel containing a maximum of 1 gr/100 CF is accepted as BACT for SO_2 control for this boiler.

Summary of the BACT Determination by Department

Pollutant	Emission Limits	EPA Test Methods
COMBUSTION TURBINE		
NO_x	25 ppmvd @ 15% O_2 ISO conditions until Dec. 31, 1997 15 ppmvd @ 15% O_2 ISO conditions after Dec. 31, 1997	20
CO	30 ppmvd	10
VOC	10 ppmvd	18, 25 or 25A
PM/PM_{10}	5 lbs/hr	5, 17*, or 201A and 202
AUXILIARY BOILER		
NO_x	0.13 lbs/MMBtu	7E
PM/PM_{10}	0.01 lbs/MMBtu	5, 17*, or 201A and 202
CO	0.10 lbs/MMBtu	10
VOC	0.04 lbs/MMBtu	18, 25 or 25A
SO_2	1 gr sulfur/100 CF gas	fuel analysis
Visible Emissions	15 percent opacity	9

*Stack flue gas temperature must be less than 320°F.

Details of the Analysis May be Obtained by Contacting:
Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

Dec 29 1993
Date

Approved by:

Daniel H Thompson For
Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

29 Dec 1993
Date

Memorandum

Florida Department of
Environmental Protection

TO: Preston Lewis
John Brown
Clair Fancy

FROM: Willard Hanks

DATE: December 27, 1993

SUBJECT: Orange Cogeneration Limited Partnership

The NPS requested that Specific Condition No. 13 in the permit for the combustion turbines (CTs) be reworded to require the installation of SCR if the NO_X emissions exceeded 15 ppmvd and that DEP reserve the right to lower the NO_X limit should a SCR be installed. The condition is reworded in the Final Determination as requested.

I question the wisdom of this revision. Data in the application showed that a SCR should not be considered as BACT for economic reasons. As revised in the Final Determination, DEP has no choice but to require an SCR should the CTs be unable to reach 15 ppmvd NO_X.

I recommend Specific Condition 13 be silent on what would happen if the CTs failed to meet this limit. This would leave DEP with all options available under the regulations open to address this problems.

An alternate recommendation would be to add language to the specific condition similar to that used in the TECO - Polk County proposed permit that say, in effect, the permittee would collect data on the NO_X emissions from the CTs and revise the BACT if the CTs NO_X emissions exceeded 15 ppmvd.

I'll be glad to discuss this position with any of you.

HLR/WH/bjb

KBN

December 20, 1993

Mr. Clair Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Orange Cogeneration Limited Partnership
Permit Application AC 53-233851
Permit Review by Fish and Wildlife Service and National Park Service

Dear Clair:

This correspondence presents responses to comments made by the U.S. Fish and Wildlife Service (FWS) and National Park Service (NPS) regarding the Best Available Control Technology (BACT) analysis for Orange Cogeneration Limited Partnership's (OCLP) proposed 103 megawatt (MW) cogeneration facility to be located near Bartow, Florida. The FWS and NPS comments for which we take exception are those related to Specific Conditions 13 and 14 were dated December 16, 1993.

The Florida Department of Environmental Protection (FDEP) has proposed, in the draft permit, emission limiting standards that minimize nitrogen oxide (NO_x) emissions through the application of dry low-NO_x (DLN) burner design when firing natural gas with a maximum NO_x emission limit of 25 parts per million volume dry (ppmvd), corrected to 15 percent oxygen, until December 31, 1997. After that date, the maximum NO_x emission rate would be limited to 15 ppm. To ensure that the lower NO_x emission rate be achieved, draft permit condition Number 13 stipulates that selective catalytic reduction (SCR) may be required should the DLN burner design not achieve the lower rate. The specific wording of these conditions is consistent with recently approved permit applications (e.g., proposed Cane Island Combustion Turbine Project by Kissimmee Utility Authority, AC49-205703/PSD-FL-182) and was discussed at length with your staff. The proposed conditions provide FDEP and the applicant the flexibility to achieve the emission rate established as BACT. Lower controls can be accomplished either through an acceptable schedule as the DLN combustor technology is being developed or by requiring post-combustion emission controls (such as SCR). As cited by the NPS, DLN combustors at an emission rate of 15 ppmvd (corrected to 15 percent oxygen) would likely be the preferred control technology from a total environmental standpoint because potential problems with SCR would be avoided. If the specific condition were changed to automatically require SCR should the 15 ppmvd limit not be achieved, the FDEP's flexibility in this regard would be lost. Moreover, other environmental factors would have to be addressed (e.g., accidental release of stored ammonia, disposal of spent catalyst), some of which could potentially have significant adverse effects on the surrounding environment.

13019A1/9

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189
5680 West Cypress Street, Suite I, Tampa, Florida 33607, 813-287-1717, FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910, FAX 407-994-9393
6821 Southpoint Drive North, Suite 216, Jacksonville, Florida 32216, 904-296-9663 FAX 904-296-0146
One Church Street, Suite 801, Rockville, Maryland 20850, 301-738-1100, FAX 301-738-1105

Also, the NPS/FWS suggestion to allow for a more stringent limit if SCR were installed is unnecessary. FDEP has this ability and can revise and even lower the emission limits below those allowed in a permit based on existing regulations (F.A.C. Rule 17-4.080, Modification of Permit Conditions). Because this regulation would apply to this project, a statement including this language in the permit is not required.

Therefore, on behalf of the Orange Cogeneration Limited Partnership, it is respectfully requested that FDEP issue the final permit with Specific Conditions 13 and 14 worded as they were proposed in the draft permit. Changing these conditions, as suggested by NPS/FWS would be:

1. Inconsistent with previous FDEP actions on similar projects,
2. Unnecessary from FDEP ability to require SCR or even a lower emission limit, and
3. Removing flexibility that the FDEP has sought in allowing facilities to advance the state-of-the-art in air pollution control (i.e., dry low-NO_x combustors).

I will be attending the Mulberry Cogeneration meeting tomorrow and would like to discuss this with you at this time to address any further questions. As always, thank you for your attention and responsiveness to our concerns.

Sincerely,

Kennard F. Kosky, P.E.
President

cc: Mr. William Malenius, Ark Energy, Inc.
Mr. Thomas Donovan, Ark Energy, Inc.
Mr Ward Marshall, Central and South West Services, Inc.
Mr. Willard Hanks, FDEP

United States Department of the Interior

FISH AND WILDLIFE SERVICE
WASHINGTON, D.C. 20240

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To KEN KOSKY	From WILLARD HANKS
Co. KBN	Co. DEP
Dept.	Phone # 904/488-1344
Fax # 904/332-4189	Fax # 904/922-6979

December 16, 1993

Memorandum

To: Regional Director, Region 4

From: Chief, Air Quality Branch

Subject: Permit Review - Orange Cogeneration Limited Partnership Project, Bartow, Polk County, Florida

We have reviewed the material that the Florida Department of Environmental Regulation (FDER) forwarded to us regarding the Orange Cogeneration Limited Partnership (OCLP) project in Bartow, Polk County, Florida, located 114 km southeast of Chassahowitzka Wilderness Area (WA). The proposed 103 megawatt cogeneration facility consists of two combustion turbines, two steam generators, and one auxiliary boiler. The facility would be a significant emitter of the following pollutants:

Pollutant	Maximum Allowable Emissions (tons per year)
Nitrogen oxides (NO_x)	394
Particulate Matter (PM)	48
Carbon monoxide (CO)	288
Volatile Organic Compounds (VOC)	54

Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) would be emitted in minor quantities.

We agree that the proposed combustion controls and burning low sulfur fuel represent best available control technology (BACT) for PM, CO, VOC, SO_2, and H_2SO_4. OCLP proposes to use dry low-NO_x combustors to reduce NO_x emissions to 15 parts per million (ppm). We ask that FDER revise the permit conditions so that OCLP would be required to apply Selective Catalytic Reduction (SCR) for additional NO_x control if the dry low-NO_x combustors cannot achieve the 15 ppm limit. We also ask that the permit include the statement that FDER may revise and lower the allowable BACT limit to less than 15 ppm if such a lower rate is achievable in the future.

The Class I Air Quality analysis predicted that emissions from the OCLP facility would result in concentrations of NO_2 and PM at the wilderness area well below the recommended Class I significant impact levels. The proposed OCLP facility will not significantly consume NO_2 or PM Class I increments at Chassahowitzka WA.

A visibility analysis was performed with the EPA VISCREEN model. The Level I VISCREEN analysis indicates that the proposed OCLP facility has low potential for visibility impairment due to plumes in Chassahowitzka WA.

OCLP did not analyze potential impacts of their emissions to air quality related values (AQRVs), other than visibility, at the wilderness area. They incorrectly concluded that, because the air quality analysis predicted that concentrations of NO_2 and PM at the wilderness area from their emissions would be below Class I significant impact levels, there would be no impact on AQRVs. In the attached letter, we remind FDER that these significance levels are to be used to determine whether a source contributes significantly to Class I increment consumption, but should not be used to determine whether a source would impact AQRVs. It is the responsibility of the Federal Land Manager to make this determination. After reviewing the OCLP application and FDER's Technical Evaluation and Preliminary Determination, we have concluded that there is low potential for impacts on the AQRVs of the wilderness area from the proposed project. However, we ask that FDER require future permit applicants to consider cumulative impacts to AQRVs even if a proposed project is not predicted to exceed Class I significant impact levels.

In conclusion, because of the relatively low emissions, and the distance from the wilderness area, we do not anticipate that resources at Chassahowitzka WA will be adversely affected by emissions from the proposed OCLP facility.

We ask that you sign the attached letter and forward it to the State immediately. We have faxed a draft copy to FDER in order to meet the comment period deadline of December 20. If you have questions, please contact me or Ellen Porter at (303) 969-2071.

Ellen L. Porter
For Sandra V. Silva

Attachment

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

Dear Mr. Fancy:

We have reviewed the Prevention of Significant Deterioration (PSD) permit application that you forwarded to us regarding Orange Cogeneration, L.P.'s (OCLP) proposed 103 MW Orange Cogeneration Facility, a combined cycle cogeneration power plant, containing two combustion turbines, two steam generators, and one auxiliary boiler. This facility would be located in Polk County near Bartow, Florida, approximately 114 km southeast of Chassahowitzka Wilderness Area (WA), a Class I air quality area administered by the U.S. Fish and Wildlife Service. The proposed project would be a significant emitter of nitrogen oxides (NO_x), particulate matter (PM), carbon monoxide (CO), and volatile organic compounds (VOC). Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) would be emitted in minor amounts.

<u>Best Available Control Technology Analysis</u>

OCLP would minimize SO_2 and H_2SO_4 emissions by using natural gas for fuel. OCLP proposes to minimize emissions of NO_x, CO, VOC, and PM from the combustion turbines by using proper combustion controls, water injection, and advanced dry low-NO_x combustors. We agree that using proper combustion controls and burning low sulfur fuel represent best available control technology (BACT) for PM, CO, VOC, SO_2, and H_2SO_4.

For minimizing NO_x emissions, we believe that either dry low-NO_x combustors, or water injection in combination with Selective Catalytic Reduction (SCR), is BACT for new combined cycle combustion turbine projects. Dry low-NO_x combustors can reduce NO_x levels to less than 15 parts per million (ppm) when firing natural gas, while SCR can achieve flue gas NO_x concentrations as low as 6 ppm when burning gas and 9 ppm when burning oil.

Recent PSD permit applicants have been looking for ways to inherently lower emissions from combustion turbines, rather than opting for add-on flue gas cleaning technologies. The BACT process is thus driving emissions from combustion turbines downward, as manufacturers strive to achieve low emission levels without add-on controls. The advantages of this approach are obvious. For example, with dry low-NO_x combustors, the potential problems often cited with SCR (i.e., ammonia slip, disposal of spent catalyst, accidental release of stored ammonia, etc.) would not be a factor. Assuming this process continues, and inherently lower emitting systems are developed, such an approach may be preferred from a total environmental standpoint.

Regardless of which control technology is used, we believe that permit conditions should reflect the minimum achievable NO_x emission rates. General Electric (GE) is developing processes, using either steam/water injection or dry-low NO_x combustor technology, to achieve a NO_x control level of 15 ppm when firing natural gas. Accordingly, the FDER proposes to accept low-NO_x burner design with a maximum NO_x emission limit of 25 ppm (while burning gas) at the OCLP facility, until December 31, 1997. After that date, the maximum permitted limit would be lowered to 15 ppm. In fact, it is our understanding that GE is hoping to design combustors that achieve an even lower rate of 9 ppm. Earlier this year, we reviewed an application for turbines at Tampa Electric Company's (TECO) Mulberry facility. BACT for TECO's turbines was the use of dry-low NO_x combustors to achieve 9 ppm. Therefore, while we do not object to the FDER allowing OCLP to emit at the 25 ppm NO_x rate until GE develops the combustors, we feel that draft permit condition Number 13 should be revised. As written now, it suggests that SCR may be required if the lower NO_x emission limit of 15 ppm cannot be met. We recommend that this permit condition require OCLP to install SCR if the dry low-NO_x combustors cannot meet the 15 ppm rate, and also that it include the statement that the FDER may revise and lower the allowable BACT limit to less than 15 ppm if such a lower rate is achievable. This will make the permit consistent with the TECO determination that 9 ppm represents BACT for turbines.

Air Quality Modeling Analysis

The Class I Air Quality analysis for the proposed OCLP facility was adequately performed. The applicant applied the EPA ISCST2 model to assess the nitrogen dioxide (NO_2) and PM impacts to Chassahowitzka WA. Five years of representative meteorological data from Tampa and Ruskin, Florida (1982-1986) were used in the modeling. Concentrations were calculated at 13 discrete receptors in the wilderness area. The ISCST2 modeling indicates that the proposed OCLP facility would impact Chassahowitzka WA below the Class I significant impact level for NO_2 of 0.025 micrograms per cubic meter ($\mu g/m^3$) for the annual average and the PM annual and 24-hour significant levels of 0.08 $\mu g/m^3$ and 0.26 $\mu g/m^3$, respectively. The maximum OCLP facility Class I annual impact for NO_2 is 0.013 $\mu g/m^3$. The maximum PM Class I impact from the proposed facility is 0.0017 $\mu g/m^3$ and 0.030 $\mu g/m^3$ for the annual and 24-hour averages respectively. Therefore, the proposed OCLP facility will not significantly consume NO_2 or PM Class I increment at the wilderness area.

A visibility analysis was performed with the EPA VISCREEN model. The Level I VISCREEN analysis indicates that the proposed OCLP facility has low potential for visibility impairment due to plumes in Chassahowitzka WA.

Air Quality Related Values Analysis

OCLP incorrectly applied Class I significant impact levels in their air quality related values analysis (AQRVs). OCLP concluded that because predicted impacts of NO_2 and PM at the wilderness area would be below Class I significant impact levels, then the facility would not have a significant effect on AQRVs. These impact levels are to be used to determine if a facility would significantly contribute to increment consumption. They are not to be used to determine if a facility would affect Class I area AQRVs. This determination is to be made by the Federal Land Manager for the area on a case-specific basis, considering the existing air quality conditions, the sensitivity of the resources, and other relevant data. After reviewing the OCLP application and FDER's Technical Evaluation and Preliminary Determination, we have concluded that there is low potential for impacts on the AQRVs of the wilderness area from the proposed project. However, we ask that FDER require future permit applicants to consider cumulative impacts to AQRVs even if a proposed project is not predicted to exceed Class I significant impact levels.

Thank you for providing us the opportunity to comment on the proposed project. If you have questions, call Ellen Porter of our Air Quality Branch in Denver at (303) 969-2071.

Sincerely,

James W. Pulliam, Jr.
Regional Director

cc: Jewell Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxic Management Division
U.S. EPA, Region 4
345 Courtland Street, NE
Atlanta, Georgia 30365

bcc:
FWS-REG. 4: AQC
CHAS: Refuge Manager
AQD-DEN: Ellen Porter
National Park Service - AIR
P.O. Box 25287
Denver, CO 80225

BEST AVAILABLE COPY

MESSAGE CONFIRMATION DEC-16-'93 THU 16:35

TERM ID: 7 7999

TEL NO:

NO.	DATE	ST. TIME	TOTAL TIME	ID	DEPT CODE	OK	NG
279	12-16	16:32	00°03'34	9043324189		05	00

Willard

KBN

RECEIVED
DEC - 2 1993
Division of Air
Resources Management

December 1, 1993

Ms. Patty Adams
Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Polk County - A.P.
Orange Cogeneration Limited Partnership
Permit Application AC 53-233851

Dear Ms. Adams:

Enclosed is the affidavit of publication for the Notice of Intent to Issue for the above referenced permit application.

Please call Bob McCann at our Gainesville office with any questions or comments.

Sincerely,

A. C. Kimball
Staff Environmental Planner

ACK/.

Enclosure

xc: J. Reese
W. Marshall
M. Craig
R. Anderson
R. McCann
13019.0500 (DD)
H. Hanks
K. Zhang
B. Thomas, SW Dist.
G. Harper, EPA
J. Bunyak, NPS
J. Novak, Polk Co.

THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

State of Florida
County of Hillsborough } ss.

Before the undersigned authority personally appeared R. Putney, who on oath says that he is Accounting Manager of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE POLK

in the matter of

STATE OF FLORIDA

was published in said newspaper in the issues of

NOVEMBER 20, 1993

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

R Putney

Sworn to and subscribed before me, this 22ND *day of* NOVEMBER *, A.D. 19*93

Personally Known ✓ *or Produced Identification*

Type of Identification Produced

(SEAL)

Ira Kennedy

IRA S. KENNEDY
Notary Public, State of Florida
My Comm. expires Mar. 22, 1996
No. CC187751

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMITS

The Department of Environmental Protection gives notice of its intent to issue air pollution source construction permits (Permit Nos. AC 53-233851, AC 53-233852 and (PSD-FL-206)) to Orange Cogeneration Limited Partnership, 23046 Avenida De La Carlota, Suite 400, Laguna Hills, CA 92653. The proposed permits are for a natural gas/equivalent biogas fired 103 megawatt (MW), gross, cogeneration facility containing two combustion turbines, two heat recovery steam generators, and one 100 million British thermal unit per hour (MMBtu/hr), based on the high heating value (HHV) of the fuel, auxiliary boiler. The facility will be constructed near Orange-Co of Florida, Inc. on Clear Springs Road in Bartow, Polk County, Florida. Maximum facility emissions are estimated to be 11.6 tons per year (TPY) sulfur dioxide (SO_2), 48.2 TPY particulate matter (PM), 393.8 TPY nitrogen oxides (NOX), 287.8 TPY carbon monoxide (CO), 53.7 TPY volatile organic compounds (VOC), and 0.89 TPY sulfuric acid mist.

The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations. The emission limits for PM, NOX, CO, and VOC are established by a Best Available Control Technology (BACT) determination. Modeling results show that increases in ground-level concentrations are less than Prevention of Significant Deterioration (PSD) significant impact levels for PM, NOX, and CO. These emissions will not cause or contribute to a violation of any ambient air quality standard or PSD increment. There are no ambiant air standards or increments for VOC. The Department's basis for this intent to issue are stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by this proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under section 120.57 Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and the telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of facts which petitioner contends warrants reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this notice, in the Office of General Counsel at the above address of the Department. Failure to petition within the allotted time frame constitutes a waiver of any rights such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application 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

Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination. Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

LK1313 11/20/93

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

November 30, 1993

Mr. Charles Collins, P.E.
Department of Environmental Protection
Central District
3319 Maguire Blvd., Ste. 232
Orlando, FL 32803-3767

Dear Mr. Collins:

Enclosed is a copy of a letter from Orange Cogeneration Limited Partnership regarding work preliminary to commencing construction of a project. The proposed work is acceptable as long as it is limited to the non-structural site preparation activities and construction mobilization until the final permit is issued.

Please contact me if you have any questions.

Sincerely,

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JCB/pm

Enclosure

cc: Thomas F. Donovan, OCLP
Dennis Nester, Orange Co.

Facility is in SW District
1-3-94
Permit issued, no need to send this reply.

Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Laguna Hills, Calif. 92653

November 24, 1993

Clair Fancy, Chief
Bureau of Air Resource Management
Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Fla. 32399-2400

RE: Orange Cogeneration Project;
Initial Site Preparation Activities

Dear Mr. Fancy:

The Department of Environmental Protection recently issued its preliminary determination for a prevention of significant deterioration (PSD) permit for the Orange Cogeneration Project. The required newspaper notice of that preliminary determination was published on November 20, 1993, commencing a 30 day period for public comment on the preliminary determination, pursuant to Rule 17-210.350. At the close of that period, the Department will then be able to issue the final PSD permit.

Prior to issuance of the final PSD permit, Orange Cogeneration, Limited Partnership, will commence on the project site preliminary activities that fall within two categories. The categories of activities to be undertaken by the project construction contractor Zurn NEPCO will include non-structural site preparation activities and construction mobilization. These activities will begin on or about December 1, 1993.

The first category of activity involves site clearing, grubbing and grading, installation of the stormwater management system, and paving of a site driveway connection, approximately 20 feet long, to the adjacent public road. The second category of construction mobilization activities includes installation of temporary construction facilities, such as trailers, internal unpaved roads and construction utility service facilities. These activities will commence in the near future and require several weeks to complete. No construction of permanent facilities will commence until the final PSD permit is issued by the Department.

Based upon applicable federal PSD regulations, 40 CFR §52.21, and applicable regulatory guidance, the preliminary, non-permanent activities in these categories are allowed to be undertaken prior to issuance of the final PSD permit. This is also in accordance with prior Departmental approval of such early site preparation efforts. Orange Cogeneration L.P. understands that such preliminary efforts are at its risk that the final PSD permit may not be issued in conformance with the Department's preliminary determination. Further, such early work creates no equities in the permittee's favor for issuance of a final PSD permit.

We wished to advise the Department that these activities would begin on the project site in the near future. If you disagree with our conclusion that the described activities are appropriate during this period, please advise us as quickly as possible. If you or your staff wish to discuss this matter, please call me at 714/588-3767.

Sincerely,

Douglas S Roberts for

Thomas F. Donovan,
Program Manager

cc: Preston Lewis, DEP
Willard Hanks, DEP

I N T E R O F F I C E   M E M O R A N D U M

Date: 23-Nov-1993 08:54am EST
From: David Zell TPA
ZELL_D@A1@TPA1
Dept: Southwest District Offi
Tel No: 813/620-6100
SUNCOM:

TO: Preston Lewis TAL (LEWIS_P @ A1 @ DER)

CC: Willard Hanks TAL (HANKS_W @ A1 @ DER)

Subject: Drfat Permit for Orange Cogeneration - AC53-233851

After a quick review of the Technical Evaluation and draft construction permit for Orange Congeneration (AC53-233851/PSD-FL-206), I have a question about two of the the annual TPY emission limitations contained in Table 2. Specifically I question the Maximum Corrected TPY limitation for CO for the DLN scenario. Since the lb/hr limitation is the same for both the WI and DLN scenarios and the allowable hours/year is 8760, it appears that the TPY limit for both scenarios should be the same at 122 TPY. I have a similar question for the ISO Conditions TPY limitation for VOC under the DLN scenario. Again based on the lb/hour limit and 8760 hours/year, it appears that the TPY limit should 16.9 TPY (almost identical to the WI sceanrio which has a slightly different lb/hr limit).

GE Industrial &
Power Systems Sales

John T. Duncan
Manager

Global Developer & Non-Utility Generation Sales
General Electric Company
Bldg. 2-407, 1 River Road, Schenectady, NY 12345
(518) 385-2228, Fax (518) 385-3181

November 19, 1993

COPY

SUBJECT: Orange Cogen - LM6000 NOx Emission Capability

Mr. Anthony J. Williams
Senior Vice President
Orange Cogeneration Limited Partnership
1027 South Rainbow
Suite 360
Las Vegas, NV 89128

Mr. Mike Wilkinson
Project Engineer
Central & South West Services
P.O. Box 660164
Dallas, TX 75266-0164

Gentlemen:

GE is pleased to reaffirm the commitment, originally made by Stewart & Stevenson in a letter dated April 14, 1993, to the future NOx emission capability of the LM6000.

We understand that a 15 ppm ultimate NOx capability is likely to be required in order to obtain your air quality permit. Our LM6000 planned for Kissimmee Utility Authority (KUA) in Florida was recently permitted with this stipulation.

We'd like to state our commitment to achieve 15 ppm on the same basis as the KUA permit. Specifically, the initial NOx control capability will be 25 ppmvd @ 15% O_2. By December 31, 1997, we will be able to achieve 15 ppm NOx using an appropriate control technology. If our NOx control program allows meeting 15 ppm at an earlier date, we will provide to Orange Cogeneration Limited Partnership this capability at the same time.

We are confident that this commitment will assure you will be able to obtain the necessary permits, and we look forward to supporting your efforts.

Please acknowledge your agreement to the terms of this letter by signature of a duly authorized officer of Orange Cogeneration GP, Inc., the general partner of Orange Cogeneration Limited Partnership, in the space designated below.

Sincerely,

John T. Duncan
Manager, Global Developer & Non-Utility Generation Sales

Acknowledged:

ORANGE COGENERATION LIMITED PARTNERSHIP

By: Orange Cogeneration GP, Inc.

By:____________________________
Arnold R. Klann, President

cc: J Prochaska, S&S

R Bailey, GE M&I
R Gentner, GE Schd'y
M Grimes, GE Schd'y
L Kaplan, GE Schd'y

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Thomas F. Donovan
Orange Cogeneration Limited Partnership
1901 Clear Springs Road
Bartow, Florida 33830

4a. Article Number
P 872 562 607

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

7. Date of Delivery
2/25/94 [signature]

5. Signature (Addressee)

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

6. Signature (Agent)
Rod Parker

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 607

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to Mr. Thomas F. Donovan	
Street and No. 1901 Clear Springs Road	
P.O., State and ZIP Code Bartow, Florida 33830	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 2/23/94 AC 53-233851	

PS Form **3800**, JUNE 1991

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

November 12, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William M. Malenius
Director of Progress Development
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Laguna Hills, CA 92653

Dear Mr. Malenius:

Attached is one copy of the Technical Evaluation and Preliminary Determination, proposed Best Available Control Technology (BACT) determination, and proposed permits for the Orange Cogeneration Limited Partnership project to be located on Clear Springs Road in Bartow, Polk County, Florida.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. Preston Lewis at the above address.

Sincerely,

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

CHF/WH/bjb

Attachments

cc: B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
L. Novak, PCESD
K. Kosky, KBN

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permits by:

DEP File No. **AC** 53-233851
AC 53-233852
PSD-FL-206
Polk County

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Laguna Hills, CA 92653
_________________________________/

INTENT TO ISSUE

The Department of Environmental Protection gives notice of its intent to issue permits (copies attached) for the proposed project as detailed in the application specified above, for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, Orange Cogeneration Limited Partnership, applied on July 1, 1993, to the Department of Environmental Protection for permits to construct a natural gas/equivalent biogas fired 103 megawatt cogeneration facility consisting of two combustion turbines, two heat recovery steam generators, an auxiliary boiler, and a steam turbine generator. The cogeneration facility will be located at Orange Co of Florida, Inc.'s citrus processing plant on Clear Springs Road, Bartow, Polk County, Florida 33830.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 17-212 and 17-4. The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, Florida Statutes and Rule 17-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permits. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "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. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 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 permits.

The Department will issue the permits with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 11/18/93 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell 11/18/93
Clerk Date

Copies furnished to:

B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
L. Novak, PCESD
K. Kosky, KBN

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMITS

The Department of Environmental Protection gives notice of its intent to issue air pollution source construction permits (Permit Nos. AC 53-233851, AC 53-233852 and (PSD-FL-206)) to Orange Cogeneration Limited Partnership, 23046 Avenida De La Carlota, Suite 400, Laguna Hills, CA 92653. The proposed permits are for a natural gas/equivalent biogas fired 103 megawatt (MW), gross, cogeneration facility containing two combustion turbines, two heat recovery steam generators, and one 100 million British thermal unit per hour (MMBtu/hr), based on the higher heating value (HHV) of the fuel, auxiliary boiler. The facility will be constructed near Orange-Co of Florida, Inc., on Clear Springs Road in Bartow, Polk County, Florida. Maximum facility emissions are estimated to be 11.6 tons per year (TPY) sulfur dioxide (SO_2), 48.2 TPY particulate matter (PM), 393.8 TPY nitrogen oxides (NO_x), 287.8 TPY carbon monoxide (CO), 53.7 TPY volatile organic compounds (VOC), and 0.89 TPY sulfuric acid mist.

The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations. The emission limits for PM, NO_x, CO, and VOC are established by a Best Available Control Technology (BACT) determination. Modeling results show that increases in ground-level concentrations are less than Prevention of Significant Deterioration (PSD) significant impact levels for PM, NO_x, and CO. These emissions will not cause or contribute to a violation of any ambient air quality standard or PSD increment. There are no ambient air standards or increments for VOC. The Department's basis for this Intent to issue are stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, 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 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application 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

Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination. Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

Orange Cogeneration Limited Partnership
Bartow, Florida
Polk County

Two Combustion Turbines
One Auxiliary Boiler

Permit No. AC 53-233851
AC 53-233852
PSD-FL-206

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

November 12, 1993

I. General Information

A. Applicant

Orange Cogeneration Limited Partnership
23046 Avenida De La Carlota
Suite 400
Laguna Hills, CA 92653

B. Request

On July 1, 1993, Orange Cogeneration Limited Partnership submitted applications for permits (AC 53-233851, 233852, and PSD-FL-206) to construct a natural gas/equivalent biogas fired 103 gross megawatts (MW), cogeneration facility. The applications were considered complete on receipt of KBN's August 5, 1993, letter although refinements on the turbine performance were reported in a letter dated October 29, 1993. The cogeneration facility will be located next to Orange-Co of Florida, Inc., citrus processing plant on Clear Springs Road, Bartow, Polk County, FL 33830. The cogeneration facility will contain two combustion turbines (CT), each having a heat recovery steam generator (HRSG), and an auxiliary boiler, and one steam turbine generator. Air pollution from the CT will be controlled initially by water injection or dry low nitrogen oxides (NO_X) combustion technology.

The facility will begin operation in the simple cycle mode using one CT with water injection or low-NO_X combustion technology. It will then add a HRSG to the first CT, a second CT and HRSG, and a steam turbine to achieve a combined cycle configuration. The CTs will initially use either water injection or dry low NO_X combustion technology. By December 31, 1995, the CTs will use dry low-NO_X combustion technology to control NO_X emissions.

The auxiliary boiler is used to provide steam to the citrus plant when the steam turbine is down.

C. Emissions

The CTs and auxiliary boiler will emit the products of combustion from the burning of natural gas/equivalent biogas fuel. Clean fuel for the CTs and auxiliary boiler will minimize air pollutant emissions from these sources. The primary pollution from the CTs to be controlled is NO_X. The CTs will operate in three modes. One CT will operate in the simple cycle with water injection or low-NO_X combustion technology up to August 16, 1995. Two CTs using water injection or low-NO_X combustion technology will then operate in the combined cycle mode. By December 31, 1995, dry low NO_X combustion technology will be used to control the NO_X emissions. The NO_X emissions will be 25 parts per million by volume dry corrected to 15 percent oxygen and ISO standard ambient conditions (ppmvd @ 15% O_2 ISO conditions) initially but will be reduced to 15 ppmvd @ 15% O_2 ISO conditions by December 31, 1997.

The following tables summarize the emissions from these sources.

Table 1, Allowable Emission Rates for the Combustion Turbine
Table 2, Allowable Emission Rates for the Combustion Turbine
Table 3, Allowable Emission Rates for the Auxiliary Boiler

The proposed facility will be a major source of NO_X and CO and emit PM and VOC in quantities above the significant emission rates.

II. Rule Applicability

The proposed project, construction of a 103 MW (gross) cogeneration facility near a citrus processing plant (SIC 4911) in Polk County, is subject to the preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapter 17-4, 17-210, 17-212, 17-272, 17-275, 17-296, and 17-297, Florida Administrative Code (F.A.C.).

The facility will be located in an area designated attainment for all criteria pollutants (F.A.C. Rule 17-275.400).

The facility is on the list of major facility categories, F.A.C. Rule Table 212.400-1. It is a major source of nitrogen oxides (NO_X) and carbon monoxide (CO) because emissions of each of these pollutants exceed 100 TPY. It emits particulate matter (PM) and volatile organic compounds (VOC) in quantities above the significant emission rates. The proposed facility is subject to the Prevention of Significant Deterioration (PSD) regulations, F.A.C. Rule 17-212.400. Therefore, the project is subject to the preconstruction review requirements of F.A.C. Rule 17-212.400. The allowable emissions of all air pollutants emitted at a rate greater than significant emission rates shown in F.A.C. Rule Table 212.400-2 will be established by a Best Available Control Technology (BACT) determination (F.A.C. Rule 17-212.410). The proposed facility is also subject to the federal new source performance standards (NSPS) for small industrial steam generating units (40 CFR 60, Subpart Dc) and for stationary gas turbines (40 CFR 60, Subpart GG). The requirements of these rules will also apply to the proposed facility. The Federal Acid Rain Program requirements shall apply when those requirements become effective within Florida.

III. Technical Evaluation

The only fuel authorized for this plant is natural gas/equivalent biogas.

Biogas is a gaseous fuel composed primarily of methane that is manufactured from organic material.

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851 (PSD-FL-206)
42 MW SIMPLE CYCLE GAS TURBINE

Table 1 - Allowable Emission Rates for each combustion turbine

		Allowable Emissions Standards/Limitations[b]				
		ISO Conditions		Maximum Corrected[c]		Basis for
Pollutant[a]	Basis	lb/hr	TPY	lb/hr	TPY	Limit
NO_x	25 ppmvd[d] at 15% O_2	36.3	159.1	38.5	168.5	BACT
CO	30 ppmvd	26.8	117.5	27.8	122.0	BACT
PM/PM_{10}	0.0139 lb/MMBtu	5	21.9	5	21.9	BACT
VOC	10 ppmvd	3.83	16.8	3.98	17.4	BACT

a Pollutant emissions are based on 8,760 hours per year operation firing natural gas or equivalent biogas at 59° F.

b Emissions rates are based on 100% load and at ISO conditions. Pollutant emission rates may vary depending on the air inlet temperature to the combustion turbine (CT) and CT characteristics. Manufacturer's curves for the emission rate corrections to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination.

c Maximum emission rates not to be exceeded after correction for air inlet temperature to the combustion turbine.

d The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 at ISO conditions by 12/31/97 using appropriate combustion technology improvements. Should this level of control not be achieved when the compliance demonstration stack test are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 12/31/97, the Department may require SCR to be installed. NO_x emission concentrations are to be corrected to ISO conditions to demonstrate compliance with the NO_x emissions standard.

ORANGE COGENERATION LIMITED PARTNERSHIP
AC53-233851 (PSD-FL-206)
42 MW COMBINED CYCLE GAS TURBINE

Table 2 - Allowable Emission Rates for each combustion turbine

			Allowable Emissions Standards/Limitations[b]				
			ISO Conditions		Maximum Corrected[c]		Basis for
Pollutant[a]	Control[e]	Basis	lb/hr	TPY	lb/hr	TPY	Limit
NO_x	WI	25 ppmvd[d] at 15% O_2	36.3	159.1	38.5	168.5	BACT
	DLN	25 ppmvd at 15% O_2	34.8	152.3	37.0	161.9	BACT
CO	WI	30 ppmvd	26.8	117.5	27.8	122.0	BACT
	DLN	30 ppmvd	27	118.2	27.8	161.9	BACT
PM/PM_{10}	WI	0.0139 lb/MMBtu	5	21.9	5	21.9	BACT
	DLN	0.0147 lb/MMBtu	5	21.9	5	21.9	BACT
VOC	WI	10 ppmvd	3.83	16.8	3.98	17.4	BACT
	DLN	10 ppmvd	3.86	19.8	3.98	17.4	BACT

[a] Pollutant emissions are based on 8,760 hours per year operation firing natural gas or equivalent biogas at 59° F.

[b] Emissions rates are based on 100% load and at ISO conditions. Pollutant emission rates may vary depending on the air inlet temperature to the combustion turbine (CT) and CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 90 days after selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination.

[c] Maximum emission rates not to be exceeded after correction for air inlet temperature to the combustion turbine.

[d] The NO_x maximum concentration will be lowered to 15 ppmvd at 15% O_2 at ISO conditions by 12/31/97 using appropriate combustion technology improvements. Should this level of control not be achieved when the compliance demonstration stack test are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 12/31/97, the Department may require SCR to be installed. NO_x emission concentrations are to be corrected to ISO conditions to demonstrate compliance with the NO_x emissions standard.

[e] Wet injection (WI) and Dry Low-NO_x (DLN) combustors.

Orange Cogeneration Limited Partnership
AC 53-233852 (PSD-FL-206)

Table 3 - Allowable Emission Rates for the Auxiliary Boiler

Pollutant	lbs/MMBtu	lbs/hr	TPY
NO_x	0.13	13.0	56.9
CO	0.10	10.0	43.8
VOC	0.04	4.3	18.8
SO_2	0.003	0.3	1.3
PM/PM_{10}	0.01	1.0	4.4

COMBUSTION TURBINES (AC 53-233851)

The maximum heat input to each combustion turbine, using the lower heating value (LHV) for the fuel, will be 388 million British thermal units per hour (MMBtu/hr) with water injection and 368 MMBtu/hr with dry low NO_x control. Emissions from the two CT's will be controlled initially by water injection and meet a NO_x emission limit of 25 ppmvd @ 15% O_2 ISO conditions. Maximum NO_x emissions per CT will be 38.5 lbs/hr. The water injection control system for the CTs will be replaced with dry low NO_x combustion technology and the CTs will continue to meet a NO_x limit of 25 ppmvd @ 15% O_2 ISO conditions. By December 31, 1997, the NO_x emissions from the CTs must be reduced to 15 ppmvd @ 15% O_2 ISO conditions or the applicant will install additional air pollution controls. Should 15 ppmvd NO_x @ 15% O_2 ISO conditions not be achieved during the initial compliance tests, the applicant will provide the Department with a plan and schedule to meet this standard. If the standard has not been met by December 31, 1997, the Department may require the installation of a selective catalytic reduction system (SCR) on these CTs.

The emissions of the other criteria air pollutants (PM, CO, VOC, and SO_2) are controlled by the use of clean fuel, natural gas/equivalent biogas, and combustion control. No add-on air pollution control equipment will be required for these pollutants. The allowable emissions will be the uncontrolled emissions of these pollutants.

AUXILIARY BOILER (AC 53-233852)

The maximum heat input to the boiler using the high heating value (HHV) for the fuel will be 100 MMBtu/hr. Nitrogen oxide emissions will be controlled by low-NO_x combustors. Particulate matter and sulfur dioxide emissions will be controlled through the use of clean fuel, natural gas/equivalent biogas. Good operating practices will be used to minimize the emissions of CO and VOC.

IV. Air Quality Impact Analysis

A. Introduction

The proposed Orange Cogeneration facility will emit four pollutants in PSD significant amounts. They are the criteria pollutants carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM and PM_{10}), and ozone (O_3) (as volatile organic compounds). (Table 1)

The air quality impact analysis required by the PSD regulations for these pollutants includes:

* An analysis of existing air quality;
* A PSD increment analysis;
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts; and
* A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The AAQS analysis depends on the air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analysis, the Department has reasonable assurance that the proposed Orange Cogeneration facility, as described in this report and subject to the approval proposed herein, will not cause or contribute to a violation of any ambient air quality standard or PSD increment. A discussion of the modeling methodology and required analysis follows.

B. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimis" concentration.

The maximum concentrations predicted for the proposed project compared to the PSD de minimis monitoring concentrations are presented in Table 2. Since the maximum predicted impacts from the proposed facility are less than de minimis levels for all pollutants, preconstruction monitoring is not required for this project.

C. Modeling Methodology

1. Model Selection

The EPA-approved Industrial Source Complex (ISC2) dispersion model was used in all phases of the air quality impact analysis. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST2 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height.

2. Meteorological Data

Meteorological data used in the modeling consisted of five years (1982-1986) of hourly surface data taken at National Weather Service (NWS) station at Tampa, Florida. Mixing heights used in the modeling were based on upper air data from Ruskin (near Tampa), Florida. The NWS station in Tampa, located approximately 65 km to the west-northwest of the site, was selected for use because it is the closest primary weather station considered to have meteorological data representative of the project site. The surface observation, cloud cover, and cloud ceiling values were used in the ISCST2 meteorological preprocessor program to determine atmospheric stability using Turner stability scheme.

3. Receptor

For comparison to significant impact levels, concentrations were predicted for the following receptor locations: (1) For both simple and combined cycle operation, 81 plant boundary and near-field receptors along 36 radials with each radial spaced at 10-degree increments. (2) For simple cycle operation, 540 general grid located at distances of 200; 400; 700; 1,000; 1,500; 2,000; 2,500; 3,000; 4,000; 5,000; 6,000; 7,000; 8,000; 9,000; and 10,000 meters along 36 radials with each radials with each radials spaced at 10-degree increments. (3) For combined cycle operation, 432 general grid receptors located at distances of 400; 600; 800; 1,000; 1,500; 2,000; 2,500; 3,000; 3,500; 4,000; 4,500; and 5,000 m along 36 radials with each radial spaced at 10-degree increments.

After the screening modeling was complete, refined modeling was conducted using a receptor grid centered on the receptor that had the highest short-term concentration from the screening analysis. The receptors were located at intervals along which 9 radials spaced at 2-degree increments, centered on the radial along which the maximum concentration was produced.

The Chassahowitzka Wilderness Area is approximately 114 km from the site. The maximum PSD increment consumption at the Chassahowitzka Wilderness Area was determined for the proposed facility alone at 13 discrete receptors located along the boundary of the Class I area.

D. Results

1. Significant Impact Analysis

A summary of impacts from the screening analysis for all scenarios considered in the modeling analysis are presented in Table 2 and compared to the significant impact levels and de minimis monitoring levels.

The maximum predicted 24-hour and annual average PM/PM_{10} concentrations due to the proposed facility are 3.50 and 0.084 ug/m^3, respectively. Since these maximum concentrations are below the significance and de minimis levels, no further analysis is necessary.

The maximum predicted annual NO_2 concentrations due to the proposed facility is 0.90 ug/m^3. Because the level of impact is below the significance and de minimis levels, no further modeling analysis was performed.

The maximum predicted 1-hour and 8-hour average CO concentrations due to the proposed facility are 68.7 and 35.0 ug/m^3, respectively. These maximum impacts are less than the CO significant impact levels, so additional modeling is not required for this pollutant either.

There is currently no acceptable method to model VOC's for ozone formation. Consequently, the control of the VOC emissions are addressed in BACT review.

2. Class I Area

Maximum NO_2 and PM/PM_{10} concentrations predicted at the PSD Class I area of the Chassahowitzka National Wilderness Area for comparison to the National Park Service (NPS) recommended Class I significance levels are presented in Table 3.

The maximum NO_2 annual concentration 0.013 ug/m^3 is less than NPS Class I NO_2 annual significance level 0.025 ug/m^3.

The maximum predicted PM/PM_{10} 24-hour and annual concentration in the Class I area are 0.028 and 0.0016 ug/m^3, respectively. These predicted impacts are below the NPS Class I 24-hour and annual significance level of 0.33 and 0.08 ug/m^3.

As the results indicate, the proposed facility's impacts are below the NPS recommended Class I significance values for all averaging periods and modeled pollutants. Therefore, no further Class I modeling analysis was conducted.

3. Air Toxics Analysis

The maximum impacts of regulated and nonregulated toxic air pollutants that will be emitted by the proposed facility are presented in Table 4. The modeling results were compared to the Department's Air Toxic Reference Level. The predicted concentrations for each of these pollutants are less than their respective Air Toxic Reference Level.

Table1. Significant and Net Emission Rates (Tons Per Year)

Pollutant	Significant Emission Rate	Existing Emissions	Proposed Maximum Emissions	Net Emission Increases	Applicable Pollutant (Yes/No)
CO	100	0	280.0	280.0	Yes
SO_2	40	0	10.8	10.8	No
NO_x	40	0	375.1	375.1	Yes
PM	25	0	48.2	48.2	Yes
PM_{10}	15	0	48.2	48.2	Yes
O_3 (VOC)	40	0	52.6	52.6	Yes
H_2SO_4	7	0	0.83	0.83	No

Table 2. Maximum Air Quality Impacts for Comparison to the Significant Impact and De Minimis Ambient Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	De Minimis Level (ug/m3)
CO	1-hour	68.7	2000.0	NA
	8-hour	35.0	500.0	575.0
NO_2*	Annual	0.90	1.0	14.0
PM	24-hour	3.50	5.0	10.0
	Annual	0.084	1.0	NA
PM_{10}	24-hour	3.50	5.0	10.0
	Annual	0.084	1.0	NA
VOC	Annual	52.6 TPY	NA	100 TPY

* Assume all NO_X are converted into NO_2

Table 3. PSD Class I Increment Analysis

Pollutant	Avg. Time	Maximum Predicted Impact (ug/m3)	NPS-Recommended CLass I Significance Levels (ug/m3)
NO_2 *	Annual	0.013	0.025
$PM(PM_{10})$	24-hour	0.028	0.33
	Annual	0.0016	0.08

* Assume all NO_X are converted into NO_2

Table 4. Air Toxic Reference Level Analysis

Pollutant	Avg. Time	Maximum Predicted Impact (ug/m3)	Air Toxics Reference Level (ug/m3)
Formaldehyde	8-hour	0.035	4.5
	24-hour	0.023	1.08
	Annual	0.00064	0.077
POM **	8-hour	0.00045	NE
	24-hour	0.00029	NE
	Annual	0.00001	NE
H_2SO_4	8-hour	0.094	10
	24-hour	0.061	2.38
	Annual	0.0017	NE

** Polycyclic Organic Matter

E. Additional Impacts Analysis

1. Impacts on Soils and Vegetation

Because the predicted impacts for all pollutants considered in the analysis are less than the significant impacts, the facility is not expected to have a significant adverse effect on regional vegetation or soils.

2. Impact on Visibility

The Orange Cogeneration Facility is located approximately 114 km from the Chassahowitzka Wilderness Area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were based on maximum particulate and nitrogen oxides emissions from the facility.

Results of the Level I visibility impairment analysis demonstrate that all contract parameters have values less than the threshold values. Thus, emissions from the proposed facility will not have a significant impact on visibility at this area.

3. Growth-Related Air Quality Impacts

A limited number of personnel will be used to operate the proposed facility. These personnel are not expected to have a significant effect on the residential, commercial, and industrial growth in Polk County.

F. Conclusion

Based on the information provided by Orange Cogeneration Limited Partnership, the Department has reasonable assurance that the proposed construction/installation of the 103 MW cogeneration facility, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapters 17-212 of the Florida Administrative Code.

KBN

October 29, 1993

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
NOV 01 1993
Division of Air
Resources Management

RE: Orange Cogeneration Limited Partnership
AC53-233831 (PSD-FL-206)

Attention: Willard Hanks

Dear Willard:

As discussed during our meeting of October 27, 1993 and my letter dated October 28, 1993, there are some comments to the draft permit prepared by the Department that reflect design refinements to the project. These design refinements reflect optimization of the operating conditions for the combustion turbines (CTs) proposed for the project (i.e., LM6000). The concept for the project is focused on primarily operating the CTs at a controlled inlet air temperature of 47°F. The inlet temperature will be controlled by chillers and heaters as necessary to optimize performance. This inlet temperature of 47°F, provides peak performance as well as heat input rate. However, this operating condition falls within the curve previously established for the project. This is demonstrated by the attached curve of heat input rate as a function of inlet temperature. As shown on this figure, the maximum heat input rate occurs at 47°F but is within the data previously submitted.

The performance data including emissions for 47°F are presented in revisions to Tables 2-2, 2-3, 2-4 and 2-6 of the original application. Also attached are revisions to the appendix tables that provide the calculations and bases for the 47°F operating condition.

In addition, the stack design has been optimized to include a 11 foot diameter stack with a slightly higher exhaust temperature. Although the emission and stack changes are not significant, a modeling analysis has been performed to assure the Department that there are no changes in the air quality impacts due to the operation of the facility. This analysis is also attached and presented in revisions to Tables 7-1 through Table 7-6 of the original application.

Based on our requested changes, we are providing comments to the draft Technical Evaluation and Preliminary Determination, proposed Best Available Control Technology (BACT) determination, and proposed permits. Our comments are primarily administrative in nature and reflect minor adjustments in the permit limits. The salient comments and our rationale to certain Specific Conditions are presented below:

13019A1/6

Specific Condition 7 - We have suggested the phrase "(or equivalent)" after natural gas. Based on financial arrangements, it is possible that the facility has the opportunity to burn biogas that would be environmentally equivalent to natural gas (i.e., the fuel would have to produce emissions equivalent to or less than those of natural gas).

Specific Conditions 8 and 9 - we have included for each condition the maximum heat input at 47°F. In addition, because the LM6000 is still a relatively new machine we have added for your consideration a statement to Specific Condition 9 that would allow the maximum heat input for the CTs to be that Specific Condition 8. This would provide flexibility in the event that performance is higher, especially with the dry low-NOx combustion technology option. GE has indicated (see attached letter) that performance could produce a 6 percent higher heat input than that currently expected. As you are aware, dry low-NOx combustion technology is still under development. If the heat input rate is slightly higher under this operation, the use of the higher heat input rate Specific Condition 8 would provide margin to allow a minor increase in heat input without going back through the entire construction permitting process for a minor change.

Specific Conditions 12 and 13 - Comments to these conditions reflect our understanding that the compliance with these conditions are based on the testing procedures in Specific Conditions 17 and 18. Although it is implicit in the permit that this is the case, it is desired for financing purposes that this be stated explicitly.

Specific Condition 14 - We have offered comments that simplify this condition, since it is contemplated that the project be operated at the 47°F operating condition. A new table, Table 1, has been developed for each type of operation, i.e., water injection and dry low-NOx combustion technology . The maximum emission limits is lb/hr are those occurring at any operating temperature. We have also suggested that the maximum emission rate for either wet injection or dry low NO_x technology be incorporated as the maximum emission limits. This provides flexibility for the project and limits the maximum emissions to less than that evaluated in the impact analysis. Indeed, this condition limits the environmental impact of the project to within the bounds we have proposed.

Specific Condition 17 - We have suggested that the statement regarding the ambient temperature be taken out of this condition since the "inlet" temperature and, therefore, operating conditions will be controlled. This suggested change is consistent with Specific Condition 14 which provides for the maximum emissions.

Our other comments are relatively minor and provide refinements in the data enclosed herein.

I greatly appreciate your consideration in this matter and please call if you have any questions.

Sincerely,

Kennard F. Kosky, P.E.
President
Florida P.E. Registration No. 14996

cc: W. Malenius
R. McCann

cc: File (2)

GE Industrial &
Power Systems Sales

Robert T. Gentner
Sales Manager

Global Developer & Non-Utility Generation Sales
General Electric Company
Bldg. 2-447A, 1 River Road, Schenectady, NY 12345
(518) 385-4829, Fax (518) 385-9237

October 29, 1993

SUBJECT: GE Recommendations for Orange Cogen Air Permit

Mr. Mike Wilkinson
CSWS
FAX # 214-777-1336

Dear Mike:

The purpose of this letter is to confirm in writing GE's recommendations with regard to the fuel consumption amounts to file in your Air Permit for the Orange Cogen Project. GE has previously provided expected degradation multipliers. These multipliers could be applied to the new and clean guarantee output and heat rate values to calculate expected performance in a "non-new and clean" condition.

GE's recommendation, however, is to multiple the new and clean fuel consumption in MMBtu/hr LHV (as calculated from guaranteed heat rate and output) by 1.06 and use that fuel consumption in your Air Permit. GE feels that with operation & maintenance practices typical of IPP plants the expected fuel consumption at base load conditions of the LM6000 would not exceed 1.06 times the new and clean fuel consumption during it's life.

We would be happy to discuss this with you in greater detail if you desire.

Sincerely,

Robert T. Gentner

Robert T. Gentner
Sales Manager

cc: Len Kaplan
Vijay Patel
John Sanders
Robert Gray, GE, M&I
Bill Milham, GE, M&I
Doug Westerkamp, GE M&I

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To Mike Wilkinson	From Bob Gentner
Co.	Co.
Dept.	Phone #
Fax #	Fax #

October 28, 1993

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED

OCT 29 1993

Division of Air
Resources Management

RE: Orange Cogeneration Limited Partnership
AC53-233831 (PSD-FL-206)

Attention: Willard Hanks

Dear Willard:

This correspondence is submitted on behalf of Orange Cogeneration Limited Partnership for the purpose of waiving the Department's time requirements specified in Section 120.60(2) Florida Statutes for issuance of the preliminary determination and proposed permit. The waiver is necessary to incorporate some administrative refinements to the draft permit and would be for a period not to exceed 30 days from the date of this correspondence. It is, however, our understanding from the October 27th meeting that the Department will attempt to issue the proposed permit on or about the second week of November, as long as the requested refinements are submitted November 1, 1993.

I greatly appreciate your consideration in this matter.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

Attachment: Waiver

cc: W. Malenius
R. McCann

13019A1/5

WAIVER OF 90 DAY TIME LIMIT
UNDER SECTIONS 120.60(2) AND 403.0876, FLORIDA STATUTES

License (Permit, Certification) Application No. AC53-233831

Applicant's Name: Orange Cogeneration Limited Partnership

With regard to the above referenced application, the applicant hereby with full knowledge and understanding of applicant's rights under Sections 120.60(2) and 403.0876, Florida Statutes, waives the right to have the application approved or denied by the State of Florida Department of Environmental Regulation within the 90 day time period prescribed by law. Said waiver is made freely and voluntarily by the applicant, with full knowledge, and without any pressure or coercion by anyone employed by the State of Florida Department of Environmental Regulation.

This waiver shall expire on the 24 day of November 1993.

The undersigned is authorized to make this waiver on behalf of the applicant.

Kennard F. Kosky

Signature

Kennard F. Kosky, P.E.
Name (Please Type or Print)
Engineer-of-record

Revised April, 1990

13019A1/5/WAIVER

Best Available Copy

KBN

FACSIMILE COVER SHEET

DATE: 10-27-93

TO: WILLARD HANKS

ORGANIZATION: FLORIDA DEP

FAX NUMBER: 904-922-6979 TELEPHONE NUMBER:

FROM: BOB MCCANN

TOTAL NUMBER OF PAGES: 1 (including cover page)

MESSAGE/INSTRUCTIONS:

(1) AGENDA ITEMS (1) ADDITIONAL DATA OF ENGINE PERFORMANCE AT 47 °F INDICATES HIGHER HEAT RATE FOR DRY LOW NO_x (368 MMBTU/HR) AND WET INJECTION (388 MMBTU/HR)
(2) SHORT-TERM EMISSIONS INCREASE BY UP TO 2 TO 3%; ANNUAL BY 6%
(3) IMPACTS REMAIN THE SAME OR DO NOT TRIGGER ANY ADDITIONAL REVIEW

PROJECT NUMBER: 13019-0500 FAX OPERATOR:

(2) ATTENDEES: KEN KOSKY, BOB MCCANN KBN
MIKE WILKINSON, CENTRAL SOUTHWEST SERVICE
JEFF REESE, MK ENERGY

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FACSIMILE COVER SHEET

DATE: 10-20-93

TO: WILLARD HANKS

ORGANIZATION: FDEP

FAX NUMBER: 904-922-6979 TELEPHONE NUMBER: ____________

FROM: BOB MCCANN

TOTAL NUMBER OF PAGES: 8 (including cover page)

MESSAGE/INSTRUCTIONS:

(1) NEW ADDRESS FOR WILLIAM R. MALENIUS

23046 Avenida De La Carlota, Suite 400
Laguna Hills, CA 92653

(2) Attached EPA policy memo

PROJECT NUMBER: 13019-0500 FAX OPERATOR: ____________

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Michael L. Wilkinson, P.E.
Project Engineer

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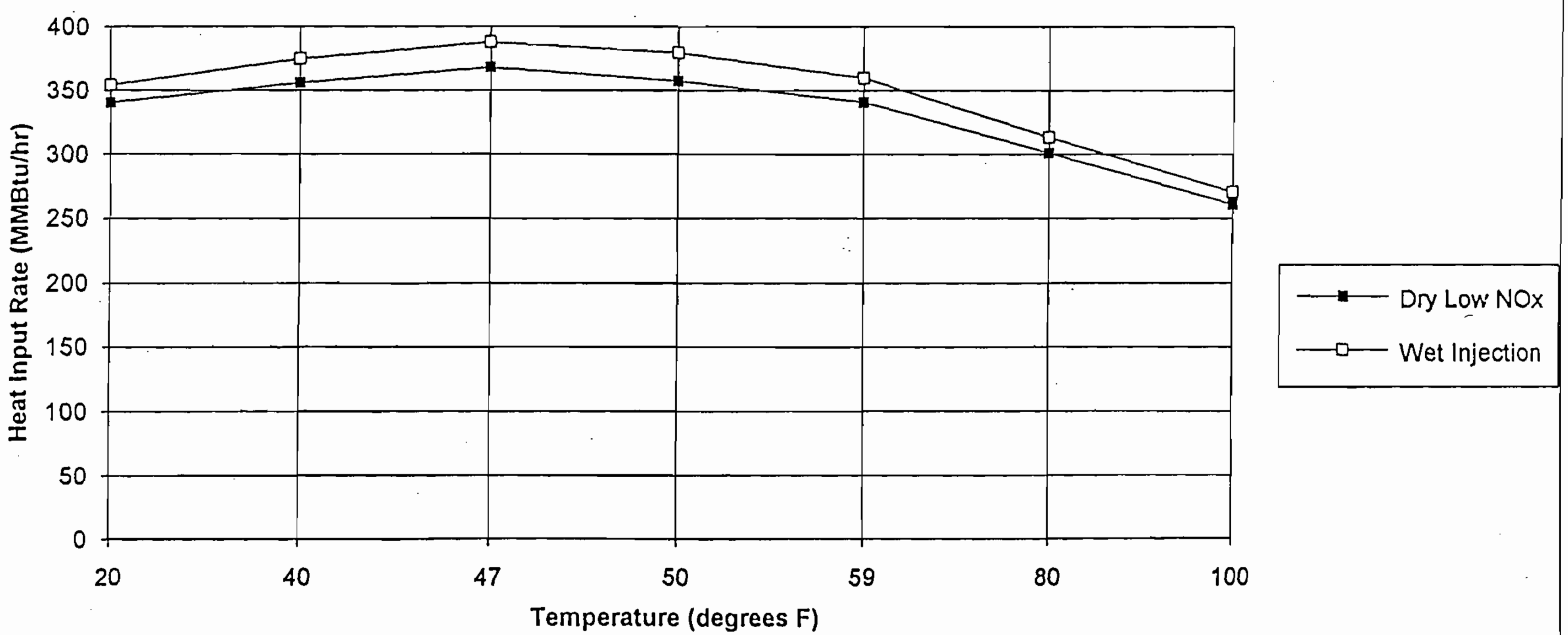
Davis G (Jeff) Reese
Manager, Legal & Public Affairs

23046 Avenida de la Carlota
Suite 400
Laguna Hills, California 92653
Telephone (714) 588-3767
Facsimile (714) 588-3972

ARK ENERGY INC.

Heat Input Rate for Various Temperature Loads (oF)



ORANGECO.XLS Chart 1
10/27/93

Revision 1
Table 2-2. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Water Injection--Simple Cycle Operation

	Operating and Emission Data[a] for Ambient Temperatures (°F) at					
Parameter	20°F	40°F	47°F	59°F	80°F	100°F
Stack Data (ft)						
Height	60	60	60	60	60	60
Diameter	9.0	9.0	9.0	9.0	9.0	9.0
Operating Data						
Temperature (°F)	754	804	831	830	842	859
Velocity (ft/sec)	142.9	149.7	151.6	145.4	132.2	119.6
Maximum Hourly Emission Data (lb/hr) Per Unit[b]						
SO_2	1.07	1.13	1.17	1.09	0.95	0.82
PM	5.0	5.0	5.0	5.0	5.0	5.0
NO_x[c]	35.7	37.8	38.5	36.3	31.6	27.3
CO	28.5	28.4	27.8	26.8	24.1	21.3
VOC	4.07	4.05	3.98	3.83	3.44	3.04
Sulfuric Acid Mist	0.082	0.087	0.090	0.083	0.072	0.063
Annual Potential Emission Data (TPY) Per Unit[b]						
SO_2	NA	NA	5.1	4.76	NA	NA
PM	NA	NA	21.9	21.9	NA	NA
NO_x[c]	NA	NA	168.5	159.1	NA	NA
CO	NA	NA	122.0	117.5	NA	NA
VOC	NA	NA	17.4	16.8	NA	NA
Sulfuric Acid Mist	NA	NA	0.39	0.36	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-1 through A-4 provide information on the simple cycle operation with wet injection.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Revision 1

Table 2-3. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Water Injection--Combined Cycle Operation

	Operating and Emission Data[a] for Ambient Temperatures (°F) at					
Parameter	20°F	40°F	47°F	59°F	80°F	100°F
Stack Data (ft)						
Height	100	100	100	100	100	100
Diameter	8.5	8.5	11.0	8.5	8.5	8.5
Operating Data						
Temperature (°F)	215	215	230	215	215	215
Velocity (ft/sec)	89.1	89.6	54.2	85.3	76.8	68.6
Maximum Hourly Emission Data (lb/hr)[b]/Per Unit						
SO_2	1.07	1.13	1.17	1.09	0.95	0.82
PM	5.0	5.0	5.0	5.0	5.0	5.0
NO_x[c]	35.7	37.8	38.5	36.3	31.6	27.3
CO	28.5	28.4	27.8	26.8	24.1	21.3
VOC	4.07	4.05	3.98	3.83	3.44	3.04
Sulfuric Acid Mist	0.082	0.087	0.090	0.083	0.072	0.063
Annual Potential Emission Data (TPY)[b]/Per Unit						
SO_2	NA	NA	5.1	4.76	NA	NA
PM	NA	NA	21.9	21.9	NA	NA
NO_x[c]	NA	NA	168.5	159.1	NA	NA
CO	NA	NA	122.0	117.5	NA	NA
VOC	NA	NA	17.4	16.8	NA	NA
Sulfuric Acid Mist	NA	NA	0.39	0.36	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-5 through A-8 provide information on combined cycle operation with wet injection.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Revision 1
Table 2-4. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Dry Low NO_x Combustion Technology--Combined Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperatures (°F) at					
	20°F	40°F	47°F	59°F	80°F	100°F
Stack Data (ft)						
Height	100	100	100	100	100	100
Diameter	8.5	8.5	11.0	8.5	8.5	8.5
Operating Data						
Temperature (°F)	215	215	230	215	215	215
Velocity (ft/sec)	86.9	86.6	52.4	82.9	75.4	67.6
Maximum Hourly Emission Data (lb/hr) Per Unit[b]						
SO_2	1.03	1.08	1.11	1.03	0.91	0.79
PM	5.0	5.0	5.0	5.0	5.0	5.0
NO_x[c]	34.7	36.3	37.0	34.8	30.7	26.6
CO	28.6	28.4	27.8	27.0	24.3	21.5
VOC	4.09	4.05	3.98	3.86	3.47	3.06
Sulfuric Acid Mist	0.079	0.082	0.085	0.079	0.070	0.060
Annual Potential Emission Data (TPY) Per Unit[b]						
SO_2	NA	NA	4.87	4.51	NA	NA
PM	NA	NA	21.9	21.9	NA	NA
NO_x[c]	NA	NA	161.9	152.3	NA	NA
CO	NA	NA	121.9	118.2	NA	NA
VOC	NA	NA	17.4	16.9	NA	NA
Sulfuric Acid Mist	NA	NA	0.37	0.35	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-9 through A-12 provide information on combined cycle operation with dry low NO_x.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Revision 1

Table 2-6. Summary of the Annual Emissions for the Proposed Combustion Turbines Operating in Simple and Combined Cycle Modes and Auxiliary Boiler

Pollutant	Emissions (TPY)[a]							
	Simple Cycle		Combined Cycle--Water Injection			Combined Cycle--Dry Low NO_x		
	CT	Total[c]	CT	AB	Total[c]	CT	AB	Total[c]
SO_2	5.13	5.13(4.76)	10.3	1.32	11.6(10.8)	9.74	1.32	11.1(10.3)
PM	21.90	21.90(21.90)	43.8	4.38	48.2(48.2)	43.8	4.38	48.2(48.2)
NO_x[b]	168.5	168.5(159.1)	336.9	56.9	393.9(375.1)	323.9	56.9	380.8(361.5)
CO	122.0	122.0(117.5)	243.9	43.8	287.7(278.9)	243.8	43.8	287.6(280.0)
VOC	17.4	17.4(16.8)	34.9	18.8	53.7(52.4)	34.8	18.8	53.7(52.6)
Sulfuric Acid Mist	0.39	0.39(0.36)	0.79	0.101	0.89(0.83)	0.75	0.101	0.85(0.79)

Note: CT = combustion turbine.
AB = auxiliary boiler.

Simple cycle operation includes one CT. Combined cycle operation includes two CTs and one AB. The CTs and AB are assumed to operate for 8,760 hours per year.

[a] Based on ambient temperature of 47°F.
[b] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume (ppmvd). After December 31, 1997, NO_x emissions will be limited to 15 ppmvd, corrected to 15 percent O_2.
[c] Numbers in parentheses are based on ambient temperature of 59°F.

Revision 1
Table 7-1. Summary of Screening Modeling Impacts for the Orange Cogeneration Facility

Pollutant	Averaging Period	Ambient Temp (°F)	Maximum Impacts ($\mu g/m^3$) Simple Cycle Operation	Combined Cycle Units Only: Water Inj	Combined Cycle Units Only: DLN	Combined Cycle Units with Aux Boiler: Water Inj	Combined Cycle Units with Aux Boiler: DLN
PM(PM10)	Annual	20	0.0059	NM	NM	NM	NM
		40	0.0055	0.055	0.056	0.083	0.084
		47	0.0053	0.050	0.052	0.082	0.084
		59	NM	0.057	0.058	0.085	0.087
		100	0.0130	0.071	0.071	0.10	0.10
	24-Hour	20	1.47	NM	NM	NM	NM
		40	1.14	2.44	2.48	2.57	2.61
		47	1.10	3.24	3.38	3.36	3.50
		59	NM	2.50	2.54	2.63	2.67
		100	3.41	3.31	3.35	3.43	3.47
NO_2	Annual	20	0.042	NM	NM	NM	NM
		40	0.041	0.41	0.41	0.87	0.88
		47	0.041	0.39	0.38	0.87	0.88
		59	NM	0.41	0.41	0.88	0.89
		100	0.069	0.39	0.38	0.90	0.90
CO	1-Hour	20	66.51	NM	NM	NM	NM
		40	59.12	44.8	45.9	58.4	58.8
		47	58.95	55.0	57.5	55.0	57.5
		59	NM	44.0	45.3	57.8	58.3
		100	70.37	41.1	41.8	55.7	56.0
	8-Hour	20	18.53	NM	NM	NM	NM
		40	14.81	24.7	25.1	26.9	29.4
		47	14.02	27.6	29.0	29.3	30.6
		59	NM	24.0	24.5	28.6	29.1
		100	27.35	21.9	22.3	27.7	28.0

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units.
Refer to Appendix B for location and time period of maximum concentrations.

DLN = dry low NO_x
NM = not modeled
Water Inj = water injection

Revision 1

Table 7-2. Summary of Overall Maximum Screening Modeling Impacts for the Orange Cogeneration Facility

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Operating Condition
PM(PM10)	Annual	0.10	Combined cycle; DLN; 100°F
		0.084	Combined cycle; DLN; 47°F
	24-Hour	3.50	Combined cycle; DLN; 100°F
		3.50	Combined cycle; DLN; 47°F
NO_2	Annual	0.90	Combined cycle; DLN; 100°F
		0.88	Combined cycle; DLN; 47°F
CO	1-Hour	70.4	Simple cycle; 100°F
		59.0	Simple cycle; 47°F
	8-Hour	29.4	Combined cycle; DLN; 40°F
		30.6	Combined cycle; DLN; 47°F

Note: Highest concentrations reported for all averaging periods. Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units.
Refer to Appendix B for location and time period of maximum concentrations.

DLN = dry low NO_x

Revision 1

Table 7-3. Summary of Maximum Refined Modeling Impacts for the Orange Cogeneration Facility

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Revised	Significant Impact Levels ($\mu g/m^3$)	*de minimus* Monitoring Level ($\mu g/m^3$)
PM(PM10)	Annual	0.10[a]	0.084[d]	1	NA
	24-Hour	3.47[a]	3.50[d]	5	10
NO_2	Annual	0.90[a]	0.90[d]	1	14
CO	1-Hour	71.3[b]	68.7[d]	2,000	NA
	8-Hour	34.8[c]	35.0[d]	500	575

Note: Highest refined concentrations reported for all averaging periods.

NA = not applicable.

[a] Combined cycle operation with DLN combustors at ambient temperature of 100°F.
[b] Simple cycle operation at ambient temperature of 100°F.
[c] Combined cycle operation with DLN combustors at ambient temperature of 40°F.
[d] Based on 47°F combined cycle.

Revision 1

Table 7-4. Summary of Maximum Predicted PM and NO_2 Concentrations Due to the Proposed Facility at the Class I Area of the Chassahowitzka National Wilderness Area

Pollutant	Averaging Period	Ambient Temp (°F)	Maximum Impacts ($\mu g/m^3$): Simple Cycle Operation	Combined Cycle Units Only: Water Inj	Combined Cycle Units Only: DLN	Combined Cycle Units with Aux Boiler: Water Inj	Combined Cycle Units with Aux Boiler: DLN
PM(PM10)	Annual	40	0.00054	0.0014	0.0014	0.0016	0.0016
		47	0.00054	0.0014	0.0014	0.0016	0.0016
		100	0.00060	0.0014	0.0014	0.0017	0.0017
	24-Hour	40	0.010	0.024	0.024	0.028	0.028
		47	0.010	0.023	0.023	0.028	0.028
		100	0.011	0.025	0.025	0.030	0.030
NO_2	Annual	40	0.0041	0.011	0.010	0.013	0.013
		47	0.0041	0.011	0.010	0.013	0.013
		100	0.0033	0.0079	0.0077	0.011	0.010

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units.
Refer to Appendix B for location and time period of maximum concentrations.

DLN = dry low NO_x
Water Inj = water injection

Revision 1
Table 7-5. Summary of Overall Maximum Predicted PM and NO_2 Concentrations Due to the Proposed Facility at the Class I Area of the Chassahowitzka National Wilderness Area

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	NPS-Recommended Class I Significance Levels ($\mu g/m^3$)	Operating Condition
PM(PM10)	Annual	0.0017	0.1	Combined Cycle; 100°F
		0.0016	0.1	Combined Cycle; 47°F
	24-Hour	0.030	0.33	Combined Cycle; 100°F
		0.028	0.33	Combined Cycle; 47°F
NO_2	Annual	0.013	0.025	Combined Cycle; 40°F
		0.013	0.025	Combined Cycle; 47°F

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units and auxiliary boiler.

Revision 1

Table 7-6. Summary of Maximum Concentrations Due to the Proposed Facility for the Air Toxic Modeling Analysis

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Revised[c]	Florida No Threat Levels ($\mu g/m^3$)
Formaldehyde	8-hour	0.031[a]	0.035	4.5
	24-hour	0.018[a]	0.023	1.08
	Annual	0.00067[b]	0.00064	0.077
Polycyclic Organic Matter	8-hour	0.00040[a]	0.00045	NE
	24-hour	0.00022[b]	0.00029	NE
	Annual	0.00001[b]	0.00001	NE
Sulfuric Acid Mist	8-hour	0.076[a]	0.094	10
	24-hour	0.043[b]	0.061	2.38
	Annual	0.0017[b]	0.0017	NE

Note: Highest concentrations reported for all averaging periods.
NE = none established.

[a] Combined cycle operation with DLN combustors at ambient temperature of 40°F.

[b] Combined cycle operation with DLN combustors at ambient temperature of 100°F.

[c] Combined cycle operation with DLN combustors at ambient temperature of 47°F.

Table A-1. Design Information and Stack Parameters for the Proposed Orange Cogen Facility, Simple Cycle Operation GE LM6000-PA, Natural Gas, Water Injection

Data	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
General	16081	16082		16084	16085	16086
Power (kW)	39,571.0	41,505.0	42,240.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,180.0	9,111.0	9,325.0	9,753.0
CT Exhaust Flow						
Mass Flow (lb/hr)	1,046,409	1,049,860	1,037,200	996,693	896,512	797,377
Temperature (oF)	754	804	831	830	842	859
Moisture (% Vol.)	8.17	9.11	10.02	9.65	10.01	10.99
Oxygen (% Vol.)	14.23	13.77	13.45	13.61	13.72	13.68
Molecular Weight	28.33	28.24	28.15	28.19	28.14	28.02
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)	39,571.0	41,505.0	42,240.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,180.0	9,111.0	9,325.0	9,753.0
Heat Input (MMBtu/hr)	354.32	374.87	387.76	359.82	313.30	270.30
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb) (cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)						
Heat Input (MMBtu/hr)	354.32	374.87	387.76	359.82	313.30	270.30
Heat Content, LHV (Btu/lb)	19,000	19,000	19,000	19,000	19,000	19,000
Natural Gas (lb/hr)	18,648.4	19,730.2	20,408.6	18,937.9	16,489.5	14,226.5
Heat Content, LHV (Btu/cf)	946	946	946	946	946	946
Natural Gas (cf/hr)	374,544	396,272	409,898	380,360	331,185	285,734
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)	1,046,409	1,049,860	1,037,200	996,693	896,512	797,377
Temperature (°F)	754	804	831	830	842	859
Molecular Weight	28.33	28.24	28.15	28.19	28.14	28.02
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)	1,046,409	1,049,860	1,037,200	996,693	896,512	797,377
Temperature (°F)	68	68	68	68	68	68
Molecular Weight	28.33	28.24	28.15	28.19	28.14	28.02
Volume Flow (scfm)	237,210	238,749	236,646	227,114	204,637	182,766
CT Stack Data						
Stack Height (ft)	60	60	60	60	60	60
Diameter (ft)	9.0	9.0	9.0	9.0	9.0	9.0
Volume Flow (acfm) from CT= [Volume flow (acfm) x (CT temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT	545,404	571,551	578,618	554,881	504,616	456,568
CT Temperature (°F)	754	804	831	830	842	859
CT Temperature (°F)	754	804	831	830	842	859
Volume Flow (acfm) from CT	545,404	571,551	578,618	554,881	504,616	456,568
Velocity (ft/sec)= Volume flow (acfm) from CT ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from CT	545,404	571,551	578,618	554,881	504,616	456,568
Diameter (ft)	9.0	9.0	9.0	9.0	9.0	9.0
Velocity (ft/sec)	142.9	149.7	151.6	145.4	132.2	119.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

Source: GE, 1993. (10/25/93)

Table A-2. Maximum Criteria Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
PM, lb/hr (manufacturer)	5.0	5.0	5.0	5.0	5.0	5.0
TPY	21.90	21.90	21.90	21.90	21.90	21.90
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100						
Natural Gas (cf/hr)	374,544	396,272	409,898	380,360	331,185	285,734
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)	2.0	2.0	2.0	2.0	2.0	2.0
SO2, lb/hr	1.07	1.13	1.17	1.09	0.95	0.82
TPY	4.69	4.96	5.13	4.76	4.14	3.58
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]						
Basis, ppm^a	25.0	25.0	25.0	25.0	25.0	25.0
Moisture (%)	8.17	9.11	10.02	9.6543	10.0102	10.9915
Oxygen (%)	14.23	13.77	13.45	13.6119	13.7157	13.6848
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Temperature (°F)	754	804	831	830	842	859
NOx, lb/hr	35.7	37.8	38.5	36.3	31.6	27.3
TPY	156.53	165.73	168.47	159.10	138.51	119.47
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm^b	30.0	30.0	30.0	30.0	30.0	30.0
Moisture (%)	8.1654	9.1117	10.02	9.6543	10.0102	10.9915
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Temperature (°F)	754	804	831	830	842	859
lb/hr	28.5	28.4	27.8	26.8	24.1	21.3
TPY	124.78	124.30	121.97	117.54	105.49	93.19
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as carbon) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm^b	10.0	10.0	10.0	10.0	10.0	10.0
Moisture (%)	8.1654	9.1117	10.02	9.6543	10.0102	10.9915
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Temperature (°F)	754	804	831	830	842	859
lb/hr	4.07	4.05	3.98	3.83	3.44	3.04
TPY	17.8	17.8	17.4	16.8	15.1	13.3
Lead (lb/hr)= Negligible						
Basis, lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA	NA

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

^a corrected to 15% O2 and dry conditions
^b corrected to dry conditions

Table A-3. Other Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Arsenic (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	0.027	0.027	0.027	0.027	0.027	0.027
	HIR (MMBtu/hr)	354.3	374.9	387.8	359.8	313.3	270.3
	lb/hr	9.57E-06	1.01E-05	1.05E-05	9.72E-06	8.46E-06	7.30E-06
	TPY	4.19E-05	4.43E-05	4.59E-05	4.26E-05	3.71E-05	3.20E-05
Fluoride (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)							
	Fraction SO2 (%)	5	5	5	5	5	5
	SO2 (lb/hr)	1.1	1.1	1.2	1.1	0.9	0.8
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53	1.53
	lb/hr	8.19E-02	8.67E-02	8.97E-02	8.32E-02	7.24E-02	6.25E-02
	TPY	3.59E-01	3.80E-01	3.93E-01	3.64E-01	3.17E-01	2.74E-01

Source: (1) DER, 1992

Table A-4. Non-Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Manganese (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113	1.113
	HIR (MMBtu/hr)	354.3	374.9	387.8	359.8	313.3	270.3
	lb/hr	3.94E-04	4.17E-04	4.32E-04	4.00E-04	3.49E-04	3.01E-04
	TPY	1.73E-03	1.83E-03	1.89E-03	1.75E-03	1.53E-03	1.32E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12	88.12
	HIR (MMBtu/hr)	354.3	374.9	387.8	359.8	313.3	270.3
	lb/hr	3.12E-02	3.30E-02	3.42E-02	3.17E-02	2.76E-02	2.38E-02
	TPY	1.37E-01	1.45E-01	1.50E-01	1.39E-01	1.21E-01	1.04E-01

Source: (1) EPA, 1990

Table A-5. Design Information and Stack Parameters for the Proposed Orange Cogen Facility, Combined Cycle Operation
GE LM6000-PA, Natural Gas, Water Injection

Data	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
General	16081	16082		16084	16085	16086
Power (kW)	39,571.0	41,505.0	42,240.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,180.0	9,111.0	9,325.0	9,753.0
CT Exhaust Flow						
Mass Flow (lb/hr)	1,046,409	1,049,860	1,037,200	996,693	896,512	797,377
Temperature (oF)	754	804	831	830	842	859
Moisture (% Vol.)	8.17	9.11	10.02	9.65	10.01	10.99
Oxygen (% Vol.)	14.23	13.77	13.45	13.61	13.72	13.68
Molecular Weight	28.33	28.24	28.15	28.19	28.14	28.02
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)	39,571.0	41,505.0	42,240.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,180.0	9,111.0	9,325.0	9,753.0
Heat Input (MMBtu/hr)	354.32	374.87	387.76	359.82	313.30	270.30
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb) (cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)						
Heat Input (MMBtu/hr)	354.32	374.87	387.76	359.82	313.30	270.30
Heat Content, LHV (Btu/lb)	19,000	19,000	19,000	19,000	19,000	19,000
Natural Gas (lb/hr)	18,648.4	19,730.2	20,408.6	18,937.9	16,489.5	14,226.5
Heat Content, LHV (Btu/cf)	946	946	946	946	946	946
Natural Gas (cf/hr)	374,544	396,272	409,898	380,360	331,185	285,734
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)	1,046,409	1,049,860	1,037,200	996,693	896,512	797,377
Temperature (°F)	754	804	831	830	842	859
Molecular Weight	28.33	28.24	28.15	28.19	28.14	28.02
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)	1,046,409	1,049,860	1,037,200	996,693	896,512	797,377
Temperature (°F)	68	68	68	68	68	68
Molecular Weight	28.33	28.24	28.15	28.19	28.14	28.02
Volume Flow (scfm)	237,210	238,749	236,646	227,114	204,637	182,766
HRSG Stack Data						
Stack Height (ft)	100	100	100	100	100	100
Diameter (ft)	8.5	8.5	11.0	8.5	8.5	8.5
Volume Flow (acfm) from HRSG= [Volume flow (acfm) from CT x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT	545,404	571,551	578,618	554,881	504,616	456,568
CT Temperature (°F)	754	804	831	830	842	859
HRSG Temperature (°F)	215	215	230	215	215	215
Volume Flow (acfm) from HRSG	303,252	305,219	309,254	290,345	261,610	233,649
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG	303,252	305,219	309,254	290,345	261,610	233,649
Diameter (ft)	8.5	8.5	11.0	8.5	8.5	8.5
Velocity (ft/sec)	89.1	89.6	54.2	85.3	76.8	68.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

Source: GE, 1993. (10/25/93)

Table A-6. Maximum Criteria Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
PM, lb/hr (manufacturer)	5.0	5.0	5.0	5.0	5.0	5.0
TPY	21.90	21.90	21.90	21.90	21.90	21.90
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100						
Natural Gas (cf/hr)	374,544	396,272	409,898	380,360	331,185	285,734
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)	2.0	2.0	2.0	2.0	2.0	2.0
SO2, lb/hr	1.07	1.13	1.17	1.09	0.95	0.82
TPY	4.69	4.96	5.13	4.76	4.14	3.58
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]						
Basis, ppm^a	25.0	25.0	25.0	25.0	25.0	25.0
Moisture (%)	8.17	9.11	10.02	9.65	10.01	10.99
Oxygen (%)	14.23	13.77	13.45	13.61	13.72	13.68
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Temperature (°F)	754	804	831	830	842	859
lb/hr	35.7	37.8	38.5	36.3	31.6	27.3
TPY	156.53	165.73	168.47	159.10	138.51	119.47
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm^b	30.0	30.0	30.0	30.0	30.0	30.0
Moisture (%)	8.17	9.11	10.02	9.65	10.01	10.99
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Temperature (°F)	754	804	831	830	842	859
lb/hr	28.5	28.4	27.8	26.8	24.1	21.3
TPY	124.78	124.30	121.97	117.54	105.49	93.19
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as carbon) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm^b	10.0	10.0	10.0	10.0	10.0	10.0
Moisture (%)	8.17	9.11	10.02	9.65	10.01	10.99
Volume Flow (acfm)	545,404	571,551	578,618	554,881	504,616	456,568
Temperature (°F)	754	804	831	830	842	859
lb/hr	4.07	4.05	3.98	3.83	3.44	3.04
TPY	17.8	17.8	17.4	16.8	15.1	13.3
Lead (lb/hr)= Negligible						
Basis, lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA	NA

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

^a corrected to 15% O2 and dry conditions
^b corrected to dry conditions

Table A-7. Other Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Arsenic (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	0.027	0.027	0.027	0.027	0.027	0.027
	HIR (MMBtu/hr)	354.3	374.9	387.8	359.8	313.3	270.3
	lb/hr	9.57E-06	1.01E-05	1.05E-05	9.72E-06	8.46E-06	7.30E-06
	TPY	4.19E-05	4.43E-05	4.59E-05	4.26E-05	3.71E-05	3.20E-05
Fluoride (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)							
	Fraction SO2 (%)	5	5	5	5	5	5
	SO2 (lb/hr)	1.1	1.1	1.2	1.1	0.9	0.8
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53	1.53
	lb/hr	8.19E-02	8.67E-02	8.97E-02	8.32E-02	7.24E-02	6.25E-02
	TPY	3.59E-01	3.80E-01	3.93E-01	3.64E-01	3.17E-01	2.74E-01

Source: (1) DER, 1992

Table A-8. Non-Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Manganese (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113	1.113
	HIR (MMBtu/hr)	354.3	374.9	387.8	359.8	313.3	270.3
	lb/hr	3.94E-04	4.17E-04	4.32E-04	4.00E-04	3.49E-04	3.01E-04
	TPY	1.73E-03	1.83E-03	1.89E-03	1.75E-03	1.53E-03	1.32E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12	88.12
	HIR (MMBtu/hr)	354.3	374.9	387.8	359.8	313.3	270.3
	lb/hr	3.12E-02	3.30E-02	3.42E-02	3.17E-02	2.76E-02	2.38E-02
	TPY	1.37E-01	1.45E-01	1.50E-01	1.39E-01	1.21E-01	1.04E-01

Source: (1) EPA, 1990

Table A-9. Design Information and Stack Parameters for the Proposed Orange Cogen Facility, Combined Cycle Operation GE LM6000-PA, Natural Gas, Dry Low NOx

Data	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
General	11011	11012		11014	11015	11016
Power (kW)	39,122.0	40,793.0	41,442.0	38,638.0	33,240.0	27,344.0
Heat Rate (Btu/kwh)	8,699.0	8,731.0	8,887.0	8,829.0	9,058.0	9,532.0
CT Exhaust Flow						
Mass Flow (lb/hr)	1,031,596	1,026,032	1,013,700	980,775	887,935	791,613
Temperature (oF)	796	852	883	873	881	887
Moisture (% Vol.)	5.54	6.08	6.88	6.58	7.45	9.02
Oxygen (% Vol.)	14.81	14.44	14.13	14.34	14.30	14.15
Molecular Weight	28.62	28.57	28.49	28.52	28.42	28.23
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)	39,122.0	40,793.0	41,442.0	38,638.0	33,240.0	27,344.0
Heat Rate (Btu/kwh)	8,699.0	8,731.0	8,887.0	8,829.0	9,058.0	9,532.0
Heat Input (MMBtu/hr)	340.32	356.16	368.30	341.13	301.09	260.64
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)						
(cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)						
Heat Input (MMBtu/hr)	340.32	356.16	368.30	341.13	301.09	260.64
Heat Content, LHV (Btu/lb)	19,000	19,000	19,000	19,000	19,000	19,000
Natural Gas (lb/hr)	17,911.7	18,745.5	19,384.0	17,954.5	15,846.7	13,718.1
Heat Content, LHV (Btu/cf)	946	946	946	946	946	946
Natural Gas (cf/hr)	359,749	376,494	389,318	360,608	318,275	275,521
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)	1,031,596	1,026,032	1,013,700	980,775	887,935	791,613
Temperature (°F)	796	852	883	873	881	887
Molecular Weight	28.62	28.57	28.49	28.52	28.42	28.23
Volume Flow (acfm)	550,717	573,084	581,189	557,641	509,736	459,410
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)	1,031,596	1,026,032	1,013,700	980,775	887,935	791,613
Temperature (°F)	68	68	68	68	68	68
Molecular Weight	28.62	28.57	28.49	28.52	28.42	28.23
Volume Flow (scfm)	231,512	230,632	228,494	220,881	200,702	180,081
HRSG Stack Data						
Stack Height (ft)	100	100	100	100	100	100
Diameter (ft)	8.5	8.5	11	8.5	8.5	8.5
Volume Flow (acfm) from HRSG= [Volume flow (acfm) from CT x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT	550,717	573,084	581,189	557,641	509,736	459,410
CT Temperature (°F)	796	852	883	873	881	887
HRSG Temperature (°F)	215	215	230	215	215	215
Volume Flow (acfm) from HRSG	295,966	294,841	298,600	282,376	256,579	230,217
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG	295,966	294,841	298,600	282,376	256,579	230,217
Diameter (ft)	8.5	8.5	11.0	8.5	8.5	8.5
Velocity (ft/sec)	86.9	86.6	52.4	82.9	75.4	67.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

Source: GE, 1993. (10/25/93)

Table A-10. Maximum Criteria Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
PM, lb/hr (manufacturer)	5.0	5.0	5.0	5.0	5.0	5.0
TPY	21.90	21.90	21.90	21.90	21.90	21.90
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100						
Natural Gas (cf/hr)	359,749	376,494	389,318	360,608	318,275	275,521
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)	2.0	2.0	2.0	2.0	2.0	2.0
SO2, lb/hr	1.03	1.08	1.11	1.03	0.91	0.79
TPY	4.50	4.71	4.87	4.51	3.98	3.45
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]						
Basis, ppm^a	25.0	25.0	25.0	25.0	25.0	25.0
Moisture (%)	5.54	6.08	6.88	6.58	7.45	9.02
Oxygen (%)	14.81	14.44	14.13	14.34	14.30	14.15
Volume Flow (acfm)	550,717	573,084	581,189	557,641	509,736	459,410
Temperature (°F)	796	852	883	873	881	887
lb/hr	34.7	36.3	37.0	34.8	30.7	26.6
TPY	151.88	159.03	161.94	152.32	134.42	116.34
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm^b	30.0	30.0	30.0	30.0	30.0	30.0
Moisture (%)	5.54	6.08	6.88	6.58	7.45	9.02
Volume Flow (acfm)	550,717	573,084	581,189	557,641	509,736	459,410
Temperature (°F)	796	852	883	873	881	887
lb/hr	28.6	28.3	27.8	27.0	24.3	21.4
TPY	125.27	124.08	121.88	118.21	106.40	93.85
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as carbon) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm^b	10.0	10.0	10.0	10.0	10.0	10.0
Moisture (%)	5.54	6.08	6.88	6.58	7.45	9.02
Volume Flow (acfm)	550,717	573,084	581,189	557,641	509,736	459,410
Temperature (°F)	796	852	883	873	881	887
lb/hr	4.09	4.05	3.98	3.86	3.47	3.06
TPY	17.9	17.7	17.4	16.9	15.2	13.4
Lead (lb/hr)= Negligible						
Basis, lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA	NA

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

^a corrected to 15% O2 dry conditions
^b corrected to dry conditions

Table A-11. Other Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Arsenic (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	0.027	0.027	0.027	0.027	0.027	0.027
	HIR (MMBtu/hr)	340.3	356.2	368.3	341.1	301.1	260.6
	lb/hr	9.19E-06	9.62E-06	9.94E-06	9.21E-06	8.13E-06	7.04E-06
	TPY	4.02E-05	4.21E-05	4.36E-05	4.03E-05	3.56E-05	3.08E-05
Fluoride (lb/hr)= Negligible							
	lb/10E+12 Btu	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)							
	Fraction SO2 (%)	5	5	5	5	5	5
	SO2 (lb/hr)	1.0	1.1	1.1	1.0	0.9	0.8
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53	1.53
	lb/hr	7.87E-02	8.24E-02	8.52E-02	7.89E-02	6.96E-02	6.03E-02
	TPY	3.45E-01	3.61E-01	3.73E-01	3.46E-01	3.05E-01	2.64E-01

Source: (1) DER, 1992

Table A-12. Non-Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 47 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Manganese (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible							
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113	1.113
	HIR (MMBtu/hr)	340.3	356.2	368.3	341.1	301.1	260.6
	lb/hr	3.79E-04	3.96E-04	4.10E-04	3.80E-04	3.35E-04	2.90E-04
	TPY	1.66E-03	1.74E-03	1.80E-03	1.66E-03	1.47E-03	1.27E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu							
	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12	88.12
	HIR (MMBtu/hr)	340.3	356.2	368.3	341.1	301.1	260.6
	lb/hr	3.00E-02	3.14E-02	3.25E-02	3.01E-02	2.65E-02	2.30E-02
	TPY	1.31E-01	1.37E-01	1.42E-01	1.32E-01	1.16E-01	1.01E-01

Source: (1) EPA, 1990

Table A-17. Summary of Maximum Pollutant Emissions for the Proposed Orange Cogeneration Facility-
Simple Cycle Operation- GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	20 °F			40 °F			47 °F			59 °F			80 °F		
		CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total
PM	lb/hr	5.00	0.00	5.00	5.00	0.00	5.00	5.00	0.00	5.00	5.00	0.00	5.00	5.00	0.00	5.00
	TPY	21.90	0.00	21.90	21.90	0.00	21.90	21.90	0.00	21.90	21.90	0.00	21.90	21.90	0.00	21.90
SO2	lb/hr	1.07	0.00	1.07	1.13	0.00	1.13	1.17	0.00	1.17	1.09	0.00	1.09	0.95	0.00	0.95
	TPY	4.69	0.00	4.69	4.96	0.00	4.96	5.13	0.00	5.13	4.76	0.00	4.76	4.14	0.00	4.14
NOx^a	lb/hr	35.74	0.00	35.74	37.84	0.00	37.84	38.46	0.00	38.46	36.32	0.00	36.32	31.62	0.00	31.62
	TPY	156.53	0.00	156.53	165.73	0.00	165.73	168.47	0.00	168.47	159.10	0.00	159.10	138.51	0.00	138.51
CO	lb/hr	28.49	0.00	28.49	28.38	0.00	28.38	27.85	0.00	27.85	26.83	0.00	26.83	24.08	0.00	24.08
	TPY	124.78	0.00	124.78	124.30	0.00	124.30	121.97	0.00	121.97	117.54	0.00	117.54	105.49	0.00	105.49
VOC	lb/hr	4.07	0.00	4.07	4.05	0.00	4.05	3.98	0.00	3.98	3.83	0.00	3.83	3.44	0.00	3.44
	TPY	17.83	0.00	17.83	17.76	0.00	17.76	17.42	0.00	17.42	16.79	0.00	16.79	15.07	0.00	15.07
Sulfuric	lb/hr	0.082	0.00	0.082	0.087	0.00	0.087	0.090	0.00	0.090	0.083	0.00	0.083	0.072	0.00	0.072
Acid Mist	TPY	0.36	0.00	0.36	0.38	0.00	0.38	0.39	0.00	0.39	0.36	0.00	0.36	0.32	0.00	0.32
POM	lb/hr	0.00039	0.00000	0.00039	0.00042	0.00000	0.00042	0.00043	0.00000	0.00043	0.00040	0.00000	0.00040	0.00035	0.00000	0.00035
	TPY	0.0017	0.0000	0.0017	0.0018	0.0000	0.0018	0.0019	0.0000	0.0019	0.0018	0.0000	0.0018	0.0015	0.0000	0.0015
Formaldehyde	lb/hr	0.03	0.00	0.03	0.03	0.00	0.03	0.03	0.00	0.03	0.03	0.00	0.03	0.03	0.00	0.03
	TPY	0.14	0.00	0.14	0.14	0.00	0.14	0.15	0.00	0.15	0.14	0.00	0.14	0.12	0.00	0.12

Note: CT = 1 combustion turbine; AB = auxiliary boiler (not in operation). All units operating for 8,760 hours per year.

^a NOx emission is based on 25 ppmvd, corrected to 15 % O2.

Table A-18. Summary of Maximum Pollutant Emissions for the Proposed Orange Cogeneration Facility-
Combined Cycle Operation- GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	20 °F			40 °F			47 °F			59 °F			80 °F		
		CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total
PM	lb/hr	10.00	1.00	11.00	10.00	1.00	11.00	10.00	1.00	11.00	10.00	1.00	11.00	10.00	1.00	11.00
	TPY	43.80	4.38	48.18	43.80	4.38	48.18	43.80	4.38	48.18	43.80	4.38	48.18	43.80	4.38	48.18
SO2	lb/hr	2.14	0.30	2.44	2.26	0.30	2.57	2.34	0.30	2.64	2.17	0.30	2.48	1.89	0.30	2.19
	TPY	9.37	1.32	10.70	9.92	1.32	11.24	10.26	1.32	11.58	9.52	1.32	10.84	8.29	1.32	9.61
NOx^a	lb/hr	71.48	13.00	84.48	75.68	13.00	88.68	76.93	13.00	89.93	72.65	13.00	85.65	63.25	13.00	76.25
	TPY	313.06	56.94	370.00	331.46	56.94	388.40	336.93	56.94	393.87	318.20	56.94	375.14	277.02	56.94	333.96
CO	lb/hr	56.98	10.00	66.98	56.76	10.00	66.76	55.70	10.00	65.70	53.67	10.00	63.67	48.17	10.00	58.17
	TPY	249.57	43.80	293.37	248.60	43.80	292.40	243.95	43.80	287.75	235.07	43.80	278.87	210.97	43.80	254.77
VOC	lb/hr	8.14	4.30	12.44	8.11	4.30	12.41	7.96	4.30	12.26	7.67	4.30	11.97	6.88	4.30	11.18
	TPY	35.65	18.83	54.49	35.51	18.83	54.35	34.85	18.83	53.68	33.58	18.83	52.42	30.14	18.83	48.97
Sulfuric	lb/hr	0.16	0.02	0.19	0.17	0.02	0.20	0.18	0.02	0.20	0.17	0.02	0.19	0.14	0.02	0.17
Acid Mist	TPY	0.72	0.10	0.82	0.76	0.10	0.86	0.79	0.10	0.89	0.73	0.10	0.83	0.63	0.10	0.74
POM	lb/hr	0.00079	0.00011	0.00090	0.00083	0.00011	0.00095	0.00086	0.00011	0.00097	0.00080	0.00011	0.00091	0.00070	0.00011	0.00081
	TPY	0.0035	0.0005	0.0039	0.0037	0.0005	0.0041	0.0038	0.0005	0.0043	0.0035	0.0005	0.0040	0.0031	0.0005	0.0035
Formaldehyde	lb/hr	0.06	0.01	0.07	0.07	0.01	0.07	0.07	0.01	0.08	0.06	0.01	0.07	0.06	0.01	0.06
	TPY	0.27	0.04	0.31	0.29	0.04	0.33	0.30	0.04	0.34	0.28	0.04	0.32	0.24	0.04	0.28

Note: CT = 2 combustion turbines; AB = auxiliary boiler. All units operating for 8,760 hours per year.

^a NOx emission is based on 25 ppmvd, corrected to 15 % O2.

Table A-19. Summary of Maximum Pollutant Emissions for the Proposed Orange Cogeneration Facility- Combined Cycle Operation- GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Units	20 °F			40 °F			47 °F			59 °F			80 °F		
		CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total
PM	lb/hr	10.00	1.00	11.00	10.00	1.00	11.00	10.00	1.00	11.00	10.00	1.00	11.00	10.00	1.00	11.00
	TPY	43.80	4.38	48.18	43.80	4.38	48.18	43.80	4.38	48.18	43.80	4.38	48.18	43.80	4.38	48.18
SO2	lb/hr	2.06	0.30	2.36	2.15	0.30	2.45	2.22	0.30	2.53	2.06	0.30	2.36	1.82	0.30	2.12
	TPY	9.00	1.32	10.33	9.42	1.32	10.75	9.74	1.32	11.07	9.03	1.32	10.35	7.97	1.32	9.29
NOx^a	lb/hr	69.35	13.00	82.35	72.62	13.00	85.62	73.95	13.00	86.95	69.55	13.00	82.55	61.38	13.00	74.38
	TPY	303.75	56.94	360.69	318.06	56.94	375.00	323.88	56.94	380.82	304.65	56.94	361.59	268.85	56.94	325.79
CO	lb/hr	57.20	10.00	67.20	56.66	10.00	66.66	55.65	10.00	65.65	53.98	10.00	63.98	48.59	10.00	58.59
	TPY	250.54	43.80	294.34	248.17	43.80	291.97	243.76	43.80	287.56	236.41	43.80	280.21	212.80	43.80	256.60
VOC	lb/hr	8.17	4.30	12.47	8.09	4.30	12.39	7.95	4.30	12.25	7.71	4.30	12.01	6.94	4.30	11.24
	TPY	35.79	18.83	54.63	35.45	18.83	54.29	34.82	18.83	53.66	33.77	18.83	52.61	30.40	18.83	49.23
Sulfuric	lb/hr	0.16	0.02	0.18	0.16	0.02	0.19	0.17	0.02	0.19	0.16	0.02	0.18	0.14	0.02	0.16
Acid Mist	TPY	0.69	0.10	0.79	0.72	0.10	0.82	0.75	0.10	0.85	0.69	0.10	0.79	0.61	0.10	0.71
POM	lb/hr	0.00076	0.00011	0.00087	0.00079	0.00011	0.00090	0.00082	0.00011	0.00093	0.00076	0.00011	0.00087	0.00067	0.00011	0.00078
	TPY	0.0033	0.0005	0.0038	0.0035	0.0005	0.0040	0.0036	0.0005	0.0041	0.0033	0.0005	0.0038	0.0029	0.0005	0.0034
Formaldehyde	lb/hr	0.06	0.01	0.07	0.06	0.01	0.07	0.06	0.01	0.07	0.06	0.01	0.07	0.05	0.01	0.06
	TPY	0.26	0.04	0.30	0.27	0.04	0.31	0.28	0.04	0.32	0.26	0.04	0.30	0.23	0.04	0.27

Note: CT = 2 combustion turbines; AB = auxiliary boiler. All units operating for 8,760 hours per year.

^a NOx emission is based on 25 ppmvd, corrected to 15 % O2.

KBN

AUG 16 1993

Department of Environmental Regulation
SOUTHWEST DISTRICT

RECEIVED
AUG 23 1993
Division of Air
Resources Management

August 12, 1993

Dr. Richard Garrity
Florida Department of Environmental Protection
Division of Air Resources Management
4520 Oak Fair Blvd.
Tampa, FL 33610

Re: Orange Cogeneration Facility
File No. AC53-233851, Orange Cogeneration Limited Partnership

Dear Mr. Garrity:

Polk County Planning Division has requested that the attached interested party letter be forwarded to you in regard to the above-referenced permit application. Please call me with any questions or comments about the attached letter.

Sincerely,

A.C. Kimball
Staff Environmental Planner

ACK/vdp.5(3)

Attachment

xc: J. Reese
W. Marshall
M. Craig
R. McMann
13019-0400(2.4)
DD

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. ~~John Brown, Air Permitting~~
2. ~~Preston, please handle~~
3. ~~[illegible] Willard~~
4. Pauly

Remarks:

Orange Cogeneration

From: David Zell, Tampa

Date 8-20-93

Phone SC 542-6100 Ext. 412

POLK COUNTY
Board of County Commissioners

Planning Division

P.O. Box 1969
330 W. Church St.
Bartow, FL 33830
(813) 534-6084
SUNCOM 569-6084
FAX (813) 534-6021

August 10, 1993

Dr. Richard Garrity
Florida Department of Environmental Protection
Division of Air Resources Management
4520 Oak Fair Blvd.
Tampa, Florida 33610

RE: Orange Cogeneration Facility
Permit Application

Dear Dr. Garrity:

This letter is to inform you that Polk County is an interested party in the permitting process for the following project:

Applicant: Orange Cogeneration Limited Partnership
Non-Certified Electric Generating Facility

Plant Location: Section 16, Township 30, Range 25
The site is located east of US 17, south of the City of Bartow, in Polk County, Florida

Please notify us of all meetings as we would like the opportunity to participate in the conditioning of the permit for the purposes of compliance with the Polk County Comprehensive Plan and site specific parameters. If this permit has already been granted or if an intent to issue has been noticed, please contact Celeste Deardorff of my staff immediately. Under provisions of Florida Statutes, we would like to comment as it relates to local issues.

Thank you for your cooperation in this matter.

Sincerely,

Robert Anders, AICP
Planning Director

xc: chron file, case file-CUP 93-09/SA 93-01
file name: p:\u\p\cmd\power\ncertpp\dep-air.2

Celeste M. Deardorff
Planner III
Polk County Planning Division
P.O. Box 1969
Bartow, Florida 33830

RE: Orange Cogeneration Facility

I have received the permit application pursuant to the above referenced project as well as Polk County's Notice of Interested Party and Notice of Participation. We will keep you informed of all proceedings and decisions in regards to this project.

AGENCY:
Florida Department of Environmental Protection
Division of Air Resources Management

____
(Signature of Permit Reviewer)

____
(date)

____
(Print Name)

____

____
(Address)

____
(Phone)

(to be retained in Planning's Case/SA File)

KBN

August 5, 1993

Mr. John C. Brown, Jr., P.E.
Administrator, Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
AUG 0 6 1993
Division of Air
Resources Management

Re: Polk County - A.P.
Orange Cogeneration Limited Partnership
Permit Application AC 53-233851

Dear John:

This correspondence and attachments present the information requested by the Department's July 22, 1993, letter and followup conversations among Mr. Ward Marshall, Central and Southwest Services, Inc., Mr. Robert McCann, KBN, and Mr. Willard Hanks, DEP.

1. The combustion turbine (CT) will be able to achieve a nitrogen oxide (NO_x) emission limit of 25 parts per million by volume, dry (ppmvd), corrected to 15 percent oxygen, while initially operating in the simple cycle mode. For simple cycle mode, this emission limit will be achieved by using water injection. Please refer to Section 2.0, specifically Tables 2-1 and 2-2, and Appendix A, Tables A-1 through A-4, for descriptions of the operation and emission limits when the CT is operating in the simple cycle mode.

2. The proposed maximum total sulfur content of 1 grain per 100 cubic feet (gr/100 cubic ft) of natural gas is based on fuel data obtained from Florida Gas Transmission which indicated a maximum sulfur content of 0.8 gr/100 cubic ft. By specifying a limit of 1 gr/100 cubic ft, a buffer of 25 percent is provided which would allow for additional sulfur in natural gas and still meet the specification. The sulfur content of 1 gr/100 cubic ft has been used on many other projects, in particular those involving CTs used in cogeneration projects (e.g., Polk Power Partners, L.P., Mulberry Cogeneration Project, Bartow, Florida, Permit Application AC 53-211670, PSD-FL-187).

3. The New Source Performance Standards (NSPS) for gas turbines, as codified in 40 CFR 60, Subpart GG, allows for a NO_x emission limit that can be adjusted upward to allow for fuel-bound nitrogen (FBN). For the proposed CTs, the NSPS limit would be 112.4 ppm (wet injection) and 115.9 ppm (dry low-NO_x combustors), corrected to 15 percent oxygen, at an FBN content of 0.015 percent by weight. However, from the best available control technology (BACT) evaluation, it is proposed that the CTs meet a NO_x emission limit of

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189
5680 West Cypress Street, Suite I, Tampa, Florida 33607, 813-287-1717, FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910, FAX 407-994-9393
6821 Southpoint Drive North, Suite 216, Jacksonville, Florida 32216, 904-296-9663 FAX 904-296-0146
One Church Street, Suite 801, Rockville, Maryland 20850, 301-738-1100, FAX 301-738-1105

25 ppmvd (water injection and/or dry low-NO_x) through December 31, 1997, and 15 ppmvd (dry low-NO_x) after December 31, 1997, when firing natural gas. Natural gas is the only fuel proposed for the project. FBN is generally associated with oil firing since natural gas is not considered to contain quantities of FBN that would increase emissions.

4. The equipment purchased for this project will be guaranteed to meet the Occupational Safety and Health Administration (OSHA) requirements. The fuel gas compressors will be housed in a cement masonry unit building. The CTs will be guaranteed to not exceed 90 A-weighted decibels (dBA) at a height of 5 ft and a distance of 3 ft from the main unit.

5. The sample ports for the heat recovery steam generator (HRSG) stack will be 4-inch pipe nipples attached to the stack wall at an elevation designed to meet the U.S. Environmental Protection Agency (EPA) guidelines for stack sampling. The HRSG stack will include a 4-ft-wide platform around the stack with climbing access meeting OSHA requirements. Although the design drawings of the stack have not been finalized, a conceptual drawing of the HRSG stack and locations of the sample ports is presented in Figure 1.

   There will be two sample ports for the auxiliary boiler stack, each with a 4-inch-diameter pipe nipple located 90 degrees apart, which will meet the EPA guidelines for stack sampling. Access to the ports will be by ladder that will extend to a 3-ft-wide platform with handrail and extending 120 degrees around the stack.

6. The production, temperature, and pressure of the steam generated by the HRSG for maximum operating conditions (normal) are as follows:

   a. High-pressure steam flow--100,000 lb/hr;
   b. High-pressure steam temperature--800 °F;
   c. High-pressure steam pressure--630 psig;
   d. Interim-pressure steam flow--30,000 lb/hr;
   e. Interim-pressure steam temperature--425 °F; and
   f. Interim-pressure steam pressure--85 psig.

7. The temperature and pressure of the steam generated by the auxiliary boiler are as follows:

   a. Steam pressure--205 psig; and
   b. Steam temperature--saturated.

8. The last two columns of Table 4-7 refer to a comparison of the electrical energy efficiency and NO_x emissions of the CTs proposed for this project (i.e., GE LM6000) relative to other CT types. In particular, the NO_x emissions of 25 and 15 ppm from a GE 7EA CT (identified in the last two columns, first row of data) are equivalent to the proposed CTs' emissions of 21.5 and 12.9 ppm, respectively.

9. Table 4-8 presents potential emission differences of the project's proposed emission limits and those emissions that can be expected with the project by applying SCR. For those pollutants with no emission changes due to the application of SCR (i.e., SCR does not control or increase a pollutant's rate), the difference is zero as indicated in the table (last column).

10. As noted in Item 3, natural gas is the only fuel intended for this project. At present, there are no plans to use an alternate fuel.

Submittal of this information should clarify questions raised by the Department in the completeness determination for the proposed emission levels and controls and other data request (except modeling) for the above-referenced project. Please call if there are any further questions on the material submitted herein.

Sincerely,

Kennard F. Kosky /VJP

Kennard F. Kosky, P.E.
President

KFK/ehj

cc: Mr. Willian Malenius, Ark Energy, Inc.
Mr. Ward Marshall, Central and South West Services, Inc.
R.C. McCann, KBN
File (2)
K. Zhang
B. Thomas, SW Dist
J. Novak, Polk County
J. Harper, EPA
J. Bunyak, NPS

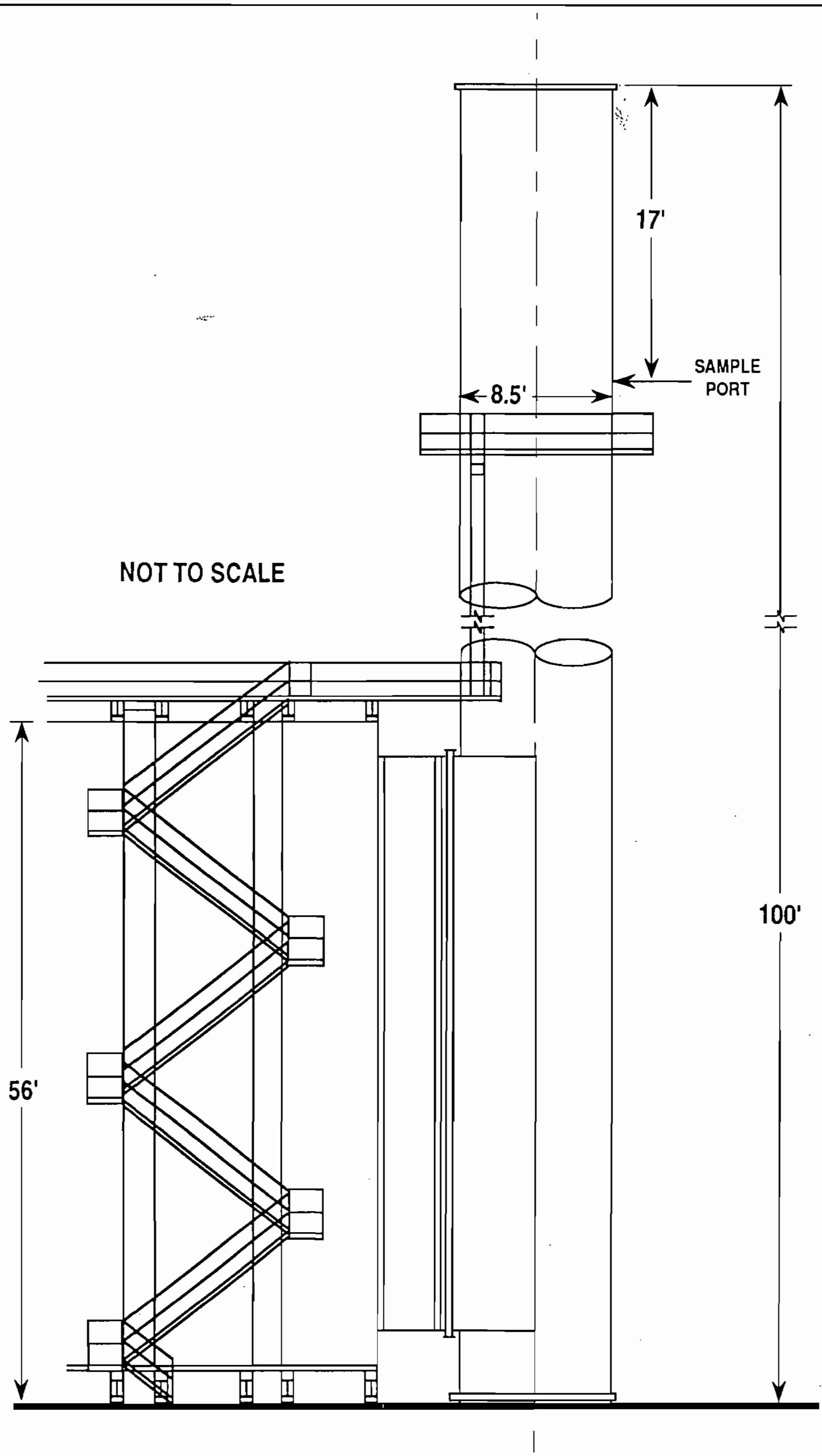


Figure 1 CONCEPTUAL DRAWING OF HRSG STACK AND ADJOINING STRUCTURE FOR THE ORANGE COGENERATION FACILITY

KBN

Patty, your copy

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 22, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Director of Project Development
Orange Cogeneration Limited Partnership
3753 Howard Hughes Parkway, Suite 200
Las Vegas, NV 89109

Dear Mr. Malenius:

Re.: File No. AC53-233851, Orange Cogeneration L.P.

The Department has reviewed your application for permit to construct a cogeneration facility in Bartow, Polk County, Florida. We will need the following additional information to continue processing this application.

1. Why is the combustion turbine unable to achieve a nitrogen oxides emission limit of 25 ppmv while initially operating in the simple cycle mode?

2. Has the supplier of the natural gas fuel for the proposed facility guaranteed that the maximum total sulfur content will not exceed 1 grain per 100 cubic feet?

3. What is the maximum fuel bound nitrogen content (percent by weight) of the natural gas? Was this nitrogen content considered in your recommended Best Available Control Technology (BACT) determination for nitrogen oxides emissions from the gas turbines?

4. What is being done to control noise from the facility? What is the design noise level for the combustion turbines?

5. Please provide drawings of the stack sampling facilities for the turbines and auxiliary boiler (access, work platforms, sampling ports).

6. What is the production, temperature and pressure of the steam generated by the heat recovery steam generators?

7. What is the temperature and pressure of the steam generated by the auxiliary boiler?

8. Please clarify the last two columns of Table 4-7.

9. Why were no emissions of particulate matter, sulfur dioxide, carbon monoxide, and volatile organic compounds listed in Table 4-8 for the project without SCR?

10. Are there any plans to use an alternate fuel for this facility?

The Department received your ambient air modeling results on July 20. There may be additional questions on it after it has been reviewed.

The Department will continue processing this application after receipt of the information requested above. If you have any questions on this matter, please write to me or call Willard Hanks (review engineer) or Kate Zhang (meteorologist) at (904) 488-1344.

Sincerely,

John C. Brown, Jr.

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JCB/WH/plm

c: B. Thomas, SWD
K. Kosky, KBN
J. Bunyak, NPS
J. Harper, EPA
L. Novak, PCESD

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Wm R. Malenius
Orange Cogeneration Limited
3753 Howard Hughes Pkwy, Ste 200
Las Vegas, NV 89109

4a. Article Number
P230523759

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

7. Date of Delivery
7/26/93

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, December 1991 ☆U.S. GPO: 1992--323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 230 523 759

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to ~~Wm R. Malenius~~	
Street and No. 3753 Howard Hughes Pkwy	
P.O., State and ZIP Code Ste. 200 ~~Las Vegas, NV 89109~~	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 7/20/93	

PS Form 3800, June 1991

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 2, 1993

Ms. Linda Novak
Polk County Board of County Commissioners
Environmental Services Department
P. O. Box 60
330 West Church Street
Bartow, FL 33830

Dear Ms. Novak:

RE: Orange Cogeneration, L.P.
Polk County, PSD-FL-206

The Department has received the above referneced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by July 28, 1993. The Bureau's FAX number is (904)922-6979.

If you have any questions, please call Preston Lewis or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

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

CHF/pa

Enclosure

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 2, 1993

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Ms. Harper:

RE: Orange Cogeneration, L.P.
Polk County, PSD-FL-206

The Department has received the above referenced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by July 28, 1993. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Preston Lewis or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

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

CHF/pa

Enclosures

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 2,1993

Mr. John Bunyak, Chief
Policy, Planning and Permit Review Branch
National Park Service-Air Quality Division
P. O. Box 25287
Denver, CO 80225

Dear Mr. Bunyak:

RE: Orange Cogeneration, L.P.
Polk County, PSD-FL-206

The Department has received the above referenced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by July 28, 1993. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Preston Lewis or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

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

CHF/pa

Enclosures

KBN

RECEIVED
JUL 01 1993
Division of Air Resources Management

June 30, 1993

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

Subject: Orange Cogeneration, L.P. - Orange Cogeneration Project

Dear Clair:

Please find enclosed five copies of the air construction permit application and prevention of significant deterioration analysis for the proposed cogeneration facility. The facility will consist of a cogeneration power plant that includes two combustion turbines and an auxiliary boiler. A check for $12,000 is enclosed to cover the appropriate permit fees for this facility ($7,500 for the turbines and $4,500 for the boiler). The computer printouts of the air quality modeling results are being sent under separate cover.

I will be contacting you in a few weeks to review the initial comments your staff may have. Please call me if there are any questions regarding this application.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/ehj

cc: William Malenius, Ark Energy, Inc.
D.G. Reese, Ark Energy, Inc.
Ward Marshall, Central and South West Services, Inc.
File (2)
J. Harper, EPA
J. Bunyak, NPS
J. Noval, Polk Co.
B. Thomas, SW Dist

13019D1/1

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189
5680 West Cypress Street, Suite I, Tampa, Florida 33607, 813-287-1717, FAX 813-287-1716
1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910, FAX 407-994-9393
6821 Southpoint Drive North, Suite 216, Jacksonville, Florida 32216, 904-296-9663 FAX 904-296-0146
One Church Street, Suite 801, Rockville, Maryland 20850, 301-738-1100, FAX 301-738-1105

7-2-93

Preston -

New application for cogen project -
This is the original file copy -
KBN is sending 2 more copies -
The rest have already been distributed
to EPA, NPS, Dist & Polk Co. Needs to
be assigned to someone & original
returned to me when copies come -

Thanks
Patty

Willard

Can you fit this in
your schedule? If not
return ASAP

Preston
7/6/93

Willard, 7-13

I think Preston
gave you the original
file copy - I need
to swap - the
extra copies came in
while I was out -
By the way, you
haven't seen the modeling
have you?

Thanks
Patty

No, Cleve?

KBN

Letter of Transmittal

Date: 07/06/93

Project No.: 13019-0500

To: Mr. Clair H. Fancy
Bureau of Air Regulation
Florida Dept of Environmental Protection
2600 Blair Stone Road
Tallahassee FL 32399

Re: Orange Cogeneration L.P.

RECEIVED
JUL 08 1993
Division of Air
Resources Management

The following items are being sent to you: ☒ with this letter ☐ under separate cover

Copies	Description
2	Air construction permit application and PSD analysis

These are transmitted:

☒ As requested ☐ For approval

☐ For review ☐ For your information

☐ For review and comment ☐

Remarks: Patty Adams requested that we provide two additional copies

Sender: Robert C. McCann

Copy to:

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street, Gainesville, Florida 32605, 904-331-9000, FAX 904-332-4189

5680 West Cypress Street, Suite I, Tampa, Florida 33607, 813-287-1717, FAX 813-287-1716

1801 Clint Moore Road, Suite 105, Boca Raton, Florida 33487, 407-994-9910, FAX 407-994-9393

6821 Southpoint Drive North, Suite 216, Jacksonville, Florida 32216, 904-296-9663 FAX 904-296-0146

One Church Street, Suite 801, Rockville, Maryland 20850, 301-738-1100, FAX 301-738-1105

XXXX/#(07/93)

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

$1500 pd.
7-1-93
Recpt #180868

AC 53-233851
PSD-FL-206

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Power Plant* [x] New[1] [ ] Existing[1]

APPLICATION TYPE: [x] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Orange Cogeneration Limited Partnership* COUNTY: *Polk*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *Two GE LM6000 Combustion Turbines*

SOURCE LOCATION: Street *Clear Springs Road* City *Bartow*

UTM: East *418.75 km (Zone 17)* North *3083.0 km*

Latitude *27* ° *52* ' *15* "N Longitude *81* ° *49* ' *31* "W

APPLICANT NAME AND TITLE: *William R. Malenius, Director of Project Development*

APPLICANT ADDRESS: *3753 Howard Hughes Parkway, Suite 200, Las Vegas, NV 89109*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Orange Cogeneration Limited Partnership*

I certify that the statements made in this application for an *air construction* permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Wm Malenius

William R. Malenius, Director of Project Development
Name and Title (Please Type)

Date: 6/24/93 Telephone No. *(714) 588-3767*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

[1]See Florida Administration Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed [signature]

Kennard F. Kosky
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 N.W. 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *14996* Date: 6/30/93 Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Construction and operation of a cogeneration facility. The power plant consists of two combustion turbines, associated heat recovery steam generators (HRSGs), one steam turbine generator, and an auxiliary fire-tube boiler. All combustion units will fire natural gas only. See Sections 1.0 and 2.0 in PSD Permit Application.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *12/01/93* Completion of Construction *12/31/95*

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

The cost of control is integral to the overall design of the project. Dry low-NO_x combustion technology will be used to reduce air pollutant emissions. See Section 4.0 in PSD Permit Application for estimated costs.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

No previous DER permits.

E. Requested permitted equipment operating time: hrs/day _*24*_; days/wk _*7*_; wks/yr _*52*_;
If power plant, hrs/yr _____; if seasonal, describe: ______

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? _*No*_
   a. If yes, has "offset" been applied? ______
   b. If yes, has "Lowest Achievable Emission Rate" been applied? ______
   c. If yes, list non-attainment pollutants. ______
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. _*Yes*[a]_
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. _*Yes*[b]_
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? _*Yes*[c]_
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? _*No*_

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? _*No*_
   a. If yes, for what pollutants? ______
   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable. ***PSD permit application attached. Full responses can be found as follows:***

[a] *Section 4.0*
[b] *Section 3.0*
[c] *Section 4.0*

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: *Not applicable.*

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) *Not applicable.*

1. Total Process Input Rate (lbs/hr): ____________________

2. Product Weight (lbs/hr): ____________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) *See Tables 2-2 through 2-6 in PSD Application*

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2 lbs/hr	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*2.26 (WI)/2.15(DLN)*	*9.5 (WI)/9.0(DLN)*	*606 (WI)/575 (DLN)*	*606(WI)/575 (DLN)*	*2.26*	*9.5*	*See*
PM	*10 (WI/DLN)*	*43.8 (WI/DLM)*	*NA*	*NA*	*10*	*43.8*	*Figure 2-1*
NO_x	*75.7 (WI)/72.6(DLN)*	*318 (WI)/305(DLN)*	*326.4(WI)/322.8(DLN)*	*326.4(WI)/322.8(DLN)*	*75.7*	*318*	*in PSD*
CO	*57.0 (WI)/57.2(DLN)*	*235 (WI)/236(DLN)*	*NA*	*NA*	*57.2*	*236*	*Application*
VOC	*8.14 (WI)/8.17(DLN)*	*33.6 (WI)/33.8(DLN)*	*NA*	*NA*	*8.17*	*33.8*	

[1]See Section V, Item 2. *Maximum (lbs/hr) at 20° to 40°F; Actual (T/yr) at 59°F. Emissions based on the maximum rates from either using wet injection (WI) or dry low NO_x combustors (DLN) to control NO_x emissions to 25 ppmvd at 15% O_2. After 12/31/97, NO_x emissions will be limited to 15 ppmvd at 15% O_2 using DLN combustors.*
[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input *75 ppmvd NO_x corrected to 15% O_2 and heat rate at ISO conditions. FDER Rule 17-2.660; 40 CFR Part 60 Subpart GG.*
[3]Calculated from operating rate and applicable standard.
[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) *See Section 4.0 in PSD application*

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas--CT	*0.7607 MMCF/hr (Wet injection, 59°F)*	*0.7925 MMCF/hr (Wet injection, 40°F)*	*749.7 (Wet injection, 40°F)*
	0.7212 MMCF/hr (Dry low NO_x, 59°F)	*0.7530 MMCF/hr (Dry low NO_x, 40°F)*	*712.3 (Dry low NO_x, 40°F)*

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis:

Percent Sulfur: *Natural gas--1 grain/100 CF;* Percent Ash: *<0.01% WGT*

Density: *Not applicable* lbs/gal Typical Percent Nitrogen: *0.03% WGT*

Heat Capacity: *Natural gas - 19,000 Btu/lb (LHV); 946 Btu/cf (LHV)* BTU/lb *Not applicable* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD permit application*

F. If applicable, indicate the percent of fuel used for space heating. *Not applicable*

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

Plant will be designed for zero wastewater discharge. Solid wastes will be disposed of in an approved manner.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: *100* ft. Stack Diameter: *8.5* ft.

Gas Flow Rate: *294,841* ACFM *230,632* DSCFM Gas Exit Temperature: *215* °F.

Water Vapor Content: *6.1* % Velocity: *86.6* FPS

See Tables in Appendix A of PSD application. Data for natural gas at 40°F shown above (general maximum emission case) for combined cycle operation with dry low NO_x combustors. See Table A-9. For data applicable for wet injection, see Table A-5.

SECTION IV: INCINERATOR INFORMATION *Not Applicable*

Type of Waste	Type O (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

Total Weight Incinerated (lbs/hr) ______ Design Capacity (lbs/hr) ______

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ______

Date Constructed ______ Model No. ______

	Volume (ft)³	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ______

Brief description of operating characteristics of control devices: ______

______

______

______

______

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

______

______

______

______

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not Applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Tables A-1 through A-12 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Tables A-1 through A-12 in PSD application.
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Sections 2.0 and 4.0 in PSD application.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   Manufacturers' expected performances form the basis of emission estimates (see Tables A-1 through A-12 in PSD application).
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-1 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 2-1 in PSD application.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
   Applicable fee is attached.
10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit. *Not Applicable*

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[*X*] Yes [ ] No

Contaminant	Rate or Concentration
NO_x - natural gas firing	*112.4 ppmvd (WI) / 115.9 ppmvd (DLN)*
	corrected to 15% O_2 and heat rate
SO_2	*0.8 percent sulfur content in fuel*

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[*X*] Yes [ ] No

Contaminant	Rate or Concentration
See Section 4.0 in PSD application	

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
See Sections 2.0 and 4.0 in PSD	
application	

D. Describe the existing control and treatment technology (if any). ***Not applicable.***

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary). ***See Section 4.0 in PSD application***

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:
b. Operating Principles:
c. Efficiency:[1]
d. Capital Cost:
e. Useful Life:
f. Operating Cost:
g. Energy:[2]
h. Maintenance Cost:
i. Availability of construction materials and process chemicals:
j. Applicability to manufacturing processes:
k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:
b. Operating Principles:
c. Efficiency:[1]
d. Capital Cost:
e. Useful Life:
f. Operating Cost:
g. Energy:[2]
h. Maintenance Cost:
i. Availability of construction materials and process chemicals:
j. Applicability to manufacturing processes:
k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected: ***See Section 4.0 in PSD application***

1. Control Device:
2. Efficiency:[1]
3. Capital Cost:
4. Useful Life:
5. Operating Cost:
6. Energy:[2]
7. Maintenance Cost:
8. Manufacturer:
9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:
(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Sections 2.0 through 7.0 in PSD application

A. Company Monitored Data ***See Section 5.0 in PSD application***

1. ____________ no. sites ____________ TSP ____________ ( ) SO_2* ____________ Wind spd/dir

Period of Monitoring ______ / ______ / ______ to ______ / ______ / ______
month day year month day year

Other data recorded ____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling *See Section 6.1 in PSD application.*

1. ______ Year(s) of data from ______/____/______ to ______/____/______
month day year month day year

2. Surface data obtained from (location)______________________

3. Upper air (mixing height) data obtained from (location) ______________________

4. Stability wind rose (STAR) data obtained from (location) ______________________

C. Computer Models Used *See Section 6.1 in PSD application.*

1. ______________________ Modified? If yes, attach description.

2. ______________________ Modified? If yes, attach description.

3. ______________________ Modified? If yes, attach description.

4. ______________________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data *See Section 6.1 in PSD application.*

Pollutant	Emission Rate	
TSP	______________________	grams/sec
SO^2	______________________	grams/sec

E. Emission Data Used in Modeling *See Section 6.0 in PSD application.*

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. *See PSD application.*

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. *See Section 4.0 in PSD application.*

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. *See Section 4.0 in PSD application.*

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

$4500 pd.
7-1-93
Recpt#180868

AC53-233852

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Power Plant* [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Orange Cogeneration Limited Partnership* COUNTY: *Polk*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *Auxiliary Boiler*

SOURCE LOCATION: Street *Clear Springs Road* City *Bartow*

UTM: East *418.75 km (Zone 17)* North *3083.0 km*

Latitude *27* ° *52* ' *15* "N Longitude *81* ° *49* ' *31* "W

APPLICANT NAME AND TITLE: *William R. Malenius, Director of Project Development*

APPLICANT ADDRESS: *3753 Howard Hughes Parkway, Suite 200, Las Vegas, NV 89109*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Orange Cogeneration Limited Partnership*

I certify that the statements made in this application for an *air construction* permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Wm Malenius

Director of
William R. Malenius, Project Development
Name and Title (Please Type)

Date: 6/24/93 Telephone No. *(714) 588-3767*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

[1]See Florida Administration Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed ______________________

Kennard F. Kosky
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 N.W. 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *14996* Date: *6/2/93* Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Construction and operation of a cogeneration facility. The power plant consists of two combustion turbines, one steam turbine generator, associated heat recovery steam generators (HRSGs), and an auxiliary fire-tube boiler. All combustion units will fire natural gas only. See Sections 1.0 and 2.0 in PSD Permit Application.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *12/01/93* Completion of Construction *12/31/95*

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

No previous DER permits.

E. Requested permitted equipment operating time: hrs/day *24*; days/wk *7*; wks/yr *52*;

If power plant, hrs/yr _____; if seasonal, describe: ______________________

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? *No*
   a. If yes, has "offset" been applied? ________
   b. If yes, has "Lowest Achievable Emission Rate" been applied? ________
   c. If yes, list non-attainment pollutants. ________
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *Yes*[a]
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*[b]
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*[c]
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? *No*

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? *No*

   a. If yes, for what pollutants? ________
   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

PSD permit application attached. Full responses can be found as follows:

[a] ***Section 4.0.***
[b] ***Section 3.0.***
[c] ***Section 4.0.***

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: *Not applicable*

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) *Not Applicable*

1. Total Process Input Rate (lbs/hr): ______

2. Product Weight (lbs/hr): ______

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

See Table 2-5 in PSD application

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*0.30*	*1.3*	*NA*	*NA*	*0.30*	*1.3*	*see*
PM	*1.0*	*4.4*	*NA*	*NA*	*1.0*	*4.4*	*Figure*
NO_x	*13.0*	*56.9*	*NA*	*NA*	*13.0*	*56.9*	*2-2 in*
CO	*10.0*	*43.8*	*NA*	*NA*	*10.0*	*43.8*	*PSD*
VOC	*4.3*	*18.8*	*NA*	*NA*	*4.3*	*18.8*	*App.*

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) *See Section 4.0 in PSD application*

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural gas	*0.105708 MMCF/hr*	*0.105708 MMCF/hr*	*100*

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis:

Percent Sulfur: *1 grain/100 CF* Percent Ash: *<0.01% WGT*

Density: *Not applicable* lbs/gal Typical Percent Nitrogen: *<0.03% WGT*

Heat Capacity: *19,000 Btu/lb (LHV)* BTU/lb *Not applicable* BTU/gal
946 Btu/cf (LHV)

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD permit application*

F. If applicable, indicate the percent of fuel used for space heating. *Not Applicable*

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

Plant will be designed for zero wastewater discharge. Solid wastes will be disposed of in an approved manner.

H.Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: ___*65*___ ft. Stack Diameter: ___*3.67*___ ft.

Gas Flow Rate: *29,731* ACFM *18,338* DSCFM Gas Exit Temperature: ___*305*___ °F.

Water Vapor Content: *approximately 10* % Velocity: ___*46.9*___ FPS

(See Table A-13 in PSD Application)

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type O (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

Total Weight Incinerated (lbs/hr) ______ Design Capacity (lbs/hr)______

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr.______

Manufacturer ______

Date Constructed ______ Model No. ______

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify)______

Brief description of operating characteristics of control devices: ______________________

____

____

____

____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

____

____

____

____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Section 2.0 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Section 2.0 in PSD application.
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Section 4.0 in PSD application.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See Section 4.0 in PSD application.
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-2 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 2-1 in PSD application.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation. ***Applicable fee is attached.***
10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [*X*] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[*X*] Yes[a] [ ] No [a]***In general***

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
See Section 4.0 in PSD application	

D. Describe the existing control and treatment technology (if any). ***Not applicable.***

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary). ***See Section 4.0 in PSD application.***

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected: ***See Section 4.0 in PSD application.***

1. Control Device: 2. Efficiency:[1]

3. Capital Cost: 4. Useful Life:

5. Operating Cost: 6. Energy:[2]

7. Maintenance Cost: 8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Sections 2.0 through 7.0 in PSD application

A. Company Monitored Data ***See Section 5.0 in PSD application***

1. ________ no. sites ________ TSP ________ ( ) SO^{2*} ________ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded ________________________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling *See Section 6.0 in PSD application*

1. ______ Year(s) of data from ______/____/______ to ______/____/______
   month day year month day year

2. Surface data obtained from (location)______________________________

3. Upper air (mixing height) data obtained from (location) ______________________

4. Stability wind rose (STAR) data obtained from (location) ______________________

C. Computer Models Used *See Section 6.0 in PSD application*

1. ______________________________ Modified? If yes, attach description.

2. ______________________________ Modified? If yes, attach description.

3. ______________________________ Modified? If yes, attach description.

4. ______________________________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data *See Section 6.0 in PSD application*

Pollutant	Emission Rate	
TSP	______________________	grams/sec
SO^2	______________________	grams/sec

E. Emission Data Used in Modeling *See Section 6.0 in PSD application*

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. *See PSD application*

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. *See Section 4.0 in PSD application*

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. *See Section 4.0 in PSD application*

DOCUMENTATION IN SUPPORT OF THE AIR CONSTRUCTION PERMIT APPLICATION

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1.0 INTRODUCTION

Orange Cogeneration Limited Partnership is proposing to construct and operate a nominal 99-megawatt (MW) cogeneration facility located in Polk County near Bartow, Florida (see Figure 1-1). The facility is referred to as the Orange Cogeneration Facility, which will be a combined cycle cogeneration power plant. The plant will provide low-pressure steam to the thermal host, Orange-Co of Florida, Inc. KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted by Orange Cogeneration Limited Partnership to provide air permitting services and perform air quality impact assessments for the project.

The plant will consist of: 1) two advanced aircraft-derivative technology combustion turbine (CT) electric generating units, each with a heat recovery steam generator (HRSG); 2) one steam turbine generator (see Table 1-1); and 3) one auxiliary boiler. The plant will have a nominal electrical output of about 99 MW to the transmission system at average ambient conditions. The primary fuel for the CTs and auxiliary boiler is natural gas.

Nitrogen oxide (NO_x) emissions from the CT units will be controlled using dry low NO_x combustion technology. The CT units using this technology may become available when the plant becomes operational. However, for purposes of this analysis, it is assumed that NO_x emissions will be controlled using water injection for the first 15 months of plant operation.

Initially, the plant will operate with one CT in simple cycle mode, using water injection to control NO_x emissions. When the plant converts to combined cycle operation (i.e. addition of another CT, two HRSGs, steam turbine generator, and auxiliary boiler), NO_x emissions will be controlled, first using water injection and then using advanced dry low-NO_x combustors to limit NO_x emissions. Exhaust gas from the CTs will be routed to the HRSGs. The steam from the HRSGs will power a steam turbine to generate electrical power of no greater than 25 MW. When the plant is operating at partial load, an auxiliary boiler may provide supplemental steam to the

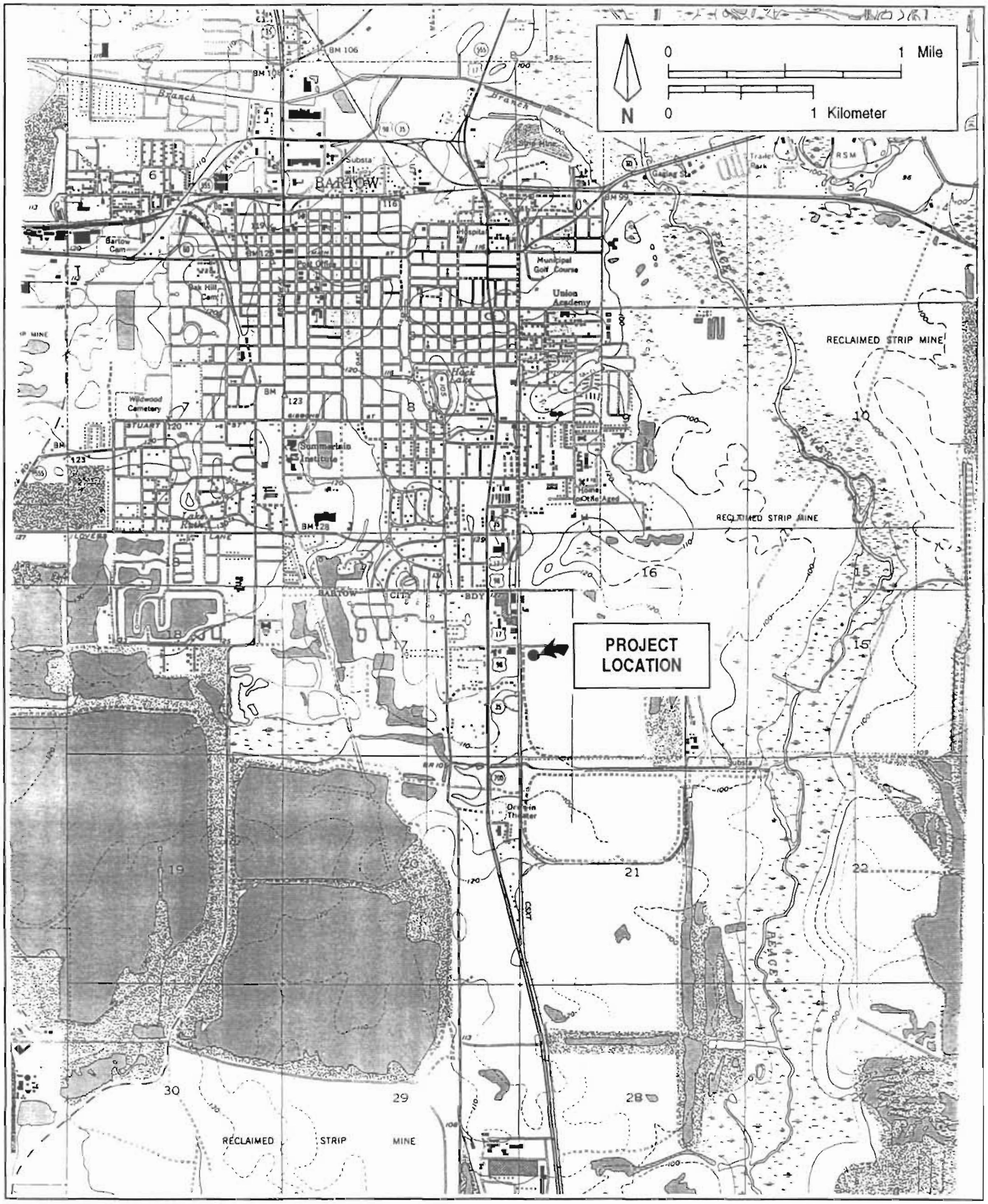


Figure 1-1 LOCATION OF PROPOSED COGENERATION FACILITY

SOURCE: USGS, 1986, 1987

Table 1-1. Characteristics of the Orange Cogeneration Facility

Characteristic	Data
Nominal Capacity	
Combustion Turbines[a]	78 MW
Steam Cycle	25 MW
Total	103 MW
Auxiliary Loads	4
Net Output	99 MW
Equipment Characteristics	
Type of CT	GE LM6000
Heat Input per Unit[a]	
- Water Injection	360 MMBtu/hr
- Dry Low NO_x	341 MMBtu/hr
Number of CTs	2
Number of HRSGs[b]	2
Number of Steam Turbines	1
Fuel	
Permanent Operation	Natural gas
Auxiliary Boiler	
Type	Fire-tube
Heat Input	100 MMBtu/hr
Fuel	Natural gas

Note: CT = combustion turbine.
GE = General Electric.
HRSG = heat recovery steam generator.
MMBtu/hr = million British thermal units per hour.

[a] Represents ISO conditions.
[b] HRSGs do not have supplemental firing.

thermal host. The auxiliary boiler is expected to have a maximum heat input of about 100 million British thermal units per hour (MMBtu/hr). Low-pressure steam will be exported to Orange-Co of Florida, Inc., located immediately to the northwest of Clear Springs Road and the CSX railroad, for process uses.

Operation of the cogeneration facility will result in the emission of air pollutants. Therefore, an air construction permit is required prior to beginning facility construction.

Because the proposed plant will be located in an attainment area for all criteria pollutants, the plant's emissions are subject to new source review (NSR) requirements as established by the Florida Department of Environmental Regulation (FDER) and the U.S. Environmental Protection Agency (EPA) under the Prevention of Significant Deterioration (PSD) regulations. The PSD review includes control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses. This report supports the air construction permit application and constitutes a PSD permit application for approval with respect to the FDER and EPA PSD regulations.

The proposed plant will be a major new source because emissions of at least one regulated pollutant exceeds 250 tons per year (TPY). PSD review is required for these emissions and for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. The potential emissions from the proposed project will exceed the PSD significant emission rates for nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 micrometers (PM10), and volatile organic compounds (VOCs). Therefore, the project is subject to PSD review for these pollutants.

This report is presented in seven sections.

- Section 2.0 -- A general description of the proposed operation.

- Section 3.0 -- The air quality review requirements and applicability of the project to the PSD and nonattainment regulations.
- Section 4.0 -- The control technology review for the project applicable under the EPA's current (draft) top-down approach.
- Section 5.0 -- A discussion of the need for air quality monitoring data to satisfy the PSD preconstruction monitoring requirements.
- Section 6.0 -- The air source impact analysis approach.
- Section 7.0 -- The results of the air quality analyses and additional impact analyses associated with the project's impacts on vegetation, soils, and associated growth

2.0 PROJECT DESCRIPTION

The Orange Cogeneration Facility will consist of two CT electrical generating units equipped with HRSGs. The CTs will be advanced aircraft-derivative technology combustion turbines that will use advanced dry low-NO_x combustors to control NO_x emissions. During combined cycle operation, the CT combustion gases will exhaust through each HRSG and into its associated stack. There will be a bypass stack for simple cycle operation of one CT up to the first 11 months of operation.

NO_x emissions for CT units will be controlled using dry low-NO_x combustion technology. The CT units using this technology may become available when the plant becomes operational. However, for purposes of this analysis, it is assumed that NO_x emissions will be controlled using water injection for the first 15 months of plant operation.

Initially, the facility will consist of one CT operating in simple cycle mode, from September 30, 1994, to August 16, 1995. NO_x emissions will be limited to 25 parts per million, corrected to dry conditions by volume (ppmvd) and 15 percent oxygen (O_2), by using water injection. As early as June 16, 1995 but no later than August 16, 1995, an additional CT will be added, together with the associated HRSGs and steam turbine, to convert the facility to combined cycle operation. NO_x emissions will be limited to 25 ppmvd, corrected to 15 percent O_2, by using water injection or dry low NO_x combustion technology. Water injection technology will be used from June 16, 1995 to as late as December 31, 1995. Dry low NO_x combustion technology will be installed no later than December 31, 1995. By December 31, 1997, NO_x emissions will be limited to 15 ppmvd, corrected to 15 percent O_2, by using advanced dry low NO_x combustion technology. The proposed schedule of the facility's operation for simple and combined cycle modes is presented in Table 2-1.

At this time, the CT being considered for this project is the General Electric (GE) LM6000-PA. Operating and emission data are available for these turbines for an operating load of 100 percent and ambient

Table 2-1. Proposed Schedule of the Simple and Combined Cycle Operation for Orange Cogeneration Facility

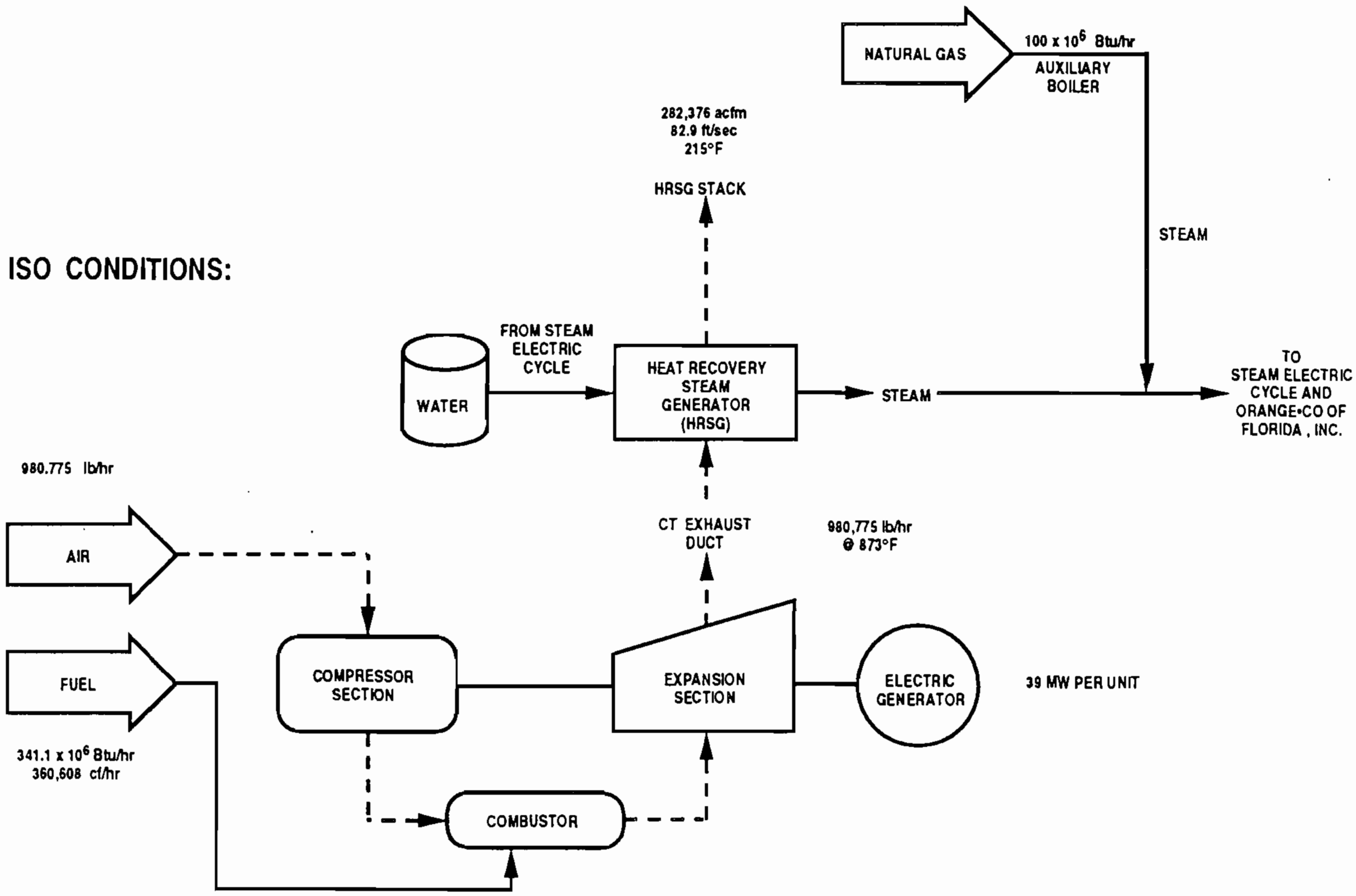
Operating Mode	NO_x Control Technology	NO_x Emission Limit (ppmvd)[a]	Date of Operation	
			Start	End
Simple Cycle	Water injection	25	09/30/94	08/16/95[b]
Combined Cycle[c]	Water injection	25	06/16/95[d]	12/31/95
Combined Cycle	Dry low NO_x	25	12/31/95	12/31/97
Combined Cycle	Dry low NO_x	15	12/31/97	Future

[a] ppmvd corrected to 15 percent O_2.
[b] End date could be 06/16/95 if additional CT, HRSGs, and steam turbine are installed.
[c] Water injection technology is planned for initial combined cycle operation. Dry low NO_x technology could be available earlier than listed.
[d] Start date could be as late as 08/16/95.

temperatures ranging from 20 to 100°F. The CT/HRSG units and the auxiliary boiler will be fired with natural gas only and are assumed to operate for 8,760 hours in a year.

Each CT will have a nominal electrical output of about 39 MW and a maximum heat input of about 360 MMBtu/hr (water injection) and 341 MMBtu/hr (dry low NO_x) at 59 degrees Fahrenheit (°F) ambient conditions. The natural-gas-fired auxiliary boiler will have a maximum heat input of 100 MMBtu/hr. The steam from the HRSGs will power a steam turbine electrical generator with maximum output of about 25 MW. Low-pressure steam will be exported to Orange-Co of Florida, Inc. for process uses. Electrical power will be sold to the electric utility grid. A process flow diagram of the facility operating in combined cycle mode is presented in Figure 2-1.

Stack, operating, and emission data for each of the proposed combustion turbines are presented in Tables 2-2 through 2-4. Emission data for the auxiliary boiler are presented in Table 2-5. Detailed information on the combustion calculations for the fuel to be fired in the CT and auxiliary boiler is presented in Appendix A. A summary of total annual emissions from the CTs operation in simple and combined cycle modes and the auxiliary boiler is presented in Table 2-6. A plot plan of the facility is presented in Figure 2-2.



NOTE: 1. SEE TABLE A-9 FOR DESIGN INFORMATION AND STACK PARAMETERS.
2. FIGURE SHOWS FLOW DIAGRAM FOR ONE COMBUSTION TURBINE AND ONE HRSG.
3. PLANT WILL CONSIST OF TWO COMBUSTION TURBINES, EACH WITH A HRSG; ONE STEAM TURBINE GENERATOR; AND ONE AUXILIARY BOILER.

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED ORANGE COGENERATION POWER PLANT — DRY LOW NO_X COMBUSTOR, COMBINED CYCLE

Table 2-2. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Water Injection--Simple Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperatures (°F) at				
	20°F	40°F	59°F	80°F	100°F
Stack Data (ft)					
Height	60	60	60	60	60
Diameter	9.0	9.0	9.0	9.0	9.0
Operating Data					
Temperature (°F)	754	804	830	842	859
Velocity (ft/sec)	142.9	149.7	145.4	132.2	119.6
Maximum Hourly Emission Data (lb/hr) Per Unit[b]					
SO_2	1.07	1.13	1.09	0.95	0.82
PM	5.0	5.0	5.0	5.0	5.0
NO_x[c]	35.7	37.8	36.3	31.6	27.3
CO	28.5	28.4	26.8	24.1	21.3
VOC	4.07	4.05	3.83	3.44	3.04
Sulfuric Acid Mist	0.082	0.087	0.083	0.072	0.063
Annual Potential Emission Data (TPY) Per Unit[b]					
SO_2	NA	NA	4.76	NA	NA
PM	NA	NA	21.9	NA	NA
NO_x[c]	NA	NA	159.1	NA	NA
CO	NA	NA	117.5	NA	NA
VOC	NA	NA	16.8	NA	NA
Sulfuric Acid Mist	NA	NA	0.36	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-1 through A-4 provide information on the simple cycle operation with wet injection.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Table 2-3. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Water Injection--Combined Cycle Operation

	Operating and Emission Data[a] for Ambient Temperatures (°F) at				
Parameter	20°F	40°F	59°F	80°F	100°F
Stack Data (ft)					
Height	100	100	100	100	100
Diameter	8.5	8.5	8.5	8.5	8.5
Operating Data					
Temperature (°F)	215	215	215	215	215
Velocity (ft/sec)	89.1	89.6	85.3	76.8	68.6
Maximum Hourly Emission Data (lb/hr)[b]/Per Unit					
SO_2	1.07	1.13	1.09	0.95	0.82
PM	5.0	5.0	5.0	5.0	5.0
NO_x[c]	35.7	37.8	36.3	31.6	27.3
CO	28.5	28.4	26.8	24.1	21.3
VOC	4.07	4.05	3.83	3.44	3.04
Sulfuric Acid Mist	0.082	0.087	0.083	0.072	0.063
Annual Potential Emission Data (TPY)[b]/Per Unit					
SO_2	NA	NA	4.76	NA	NA
PM	NA	NA	21.9	NA	NA
NO_x[c]	NA	NA	159.1	NA	NA
CO	NA	NA	117.5	NA	NA
VOC	NA	NA	16.8	NA	NA
Sulfuric Acid Mist	NA	NA	0.36	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-5 through A-8 provide information on combined cycle operation with wet injection.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Table 2-4. Stack, Operating, and Emission Data for the Proposed Combustion Turbine with Dry Low NO_x Combustion Technology--Combined Cycle Operation

Parameter	Operating and Emission Data[a] for Ambient Temperatures (°F) at				
	20°F	40°F	59°F	80°F	100°F
Stack Data (ft)					
Height	100	100	100	100	100
Diameter	8.5	8.5	8.5	8.5	8.5
Operating Data					
Temperature (°F)	215	215	215	215	215
Velocity (ft/sec)	86.9	86.6	82.9	75.4	67.6
Maximum Hourly Emission Data (lb/hr) Per Unit[b]					
SO_2	1.03	1.08	1.03	0.91	0.79
PM	5.0	5.0	5.0	5.0	5.0
NO_x[c]	34.7	36.3	34.8	30.7	26.6
CO	28.6	28.4	27.0	24.3	21.5
VOC	4.09	4.05	3.86	3.47	3.06
Sulfuric Acid Mist	0.079	0.082	0.079	0.070	0.060
Annual Potential Emission Data (TPY) Per Unit[b]					
SO_2	NA	NA	4.51	NA	NA
PM	NA	NA	21.9	NA	NA
NO_x[c]	NA	NA	152.3	NA	NA
CO	NA	NA	118.2	NA	NA
VOC	NA	NA	16.9	NA	NA
Sulfuric Acid Mist	NA	NA	0.35	NA	NA

[a] Refer to Appendix A for detailed information. Annual emission data are based on the turbine firing natural gas for 8,760 hours. Tables A-9 through A-12 provide information on combined cycle operation with dry low NO_x.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

[c] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume.

Table 2-5. Stack, Operating, and Emission Data for the Proposed Natural-Gas-Fired Auxiliary Boiler

Parameter	Operating and Emission Data[a]
Stack Data (ft)	
Height	65
Diameter	3.67
Operating Data	
Temperature (°F)	305
Velocity (ft/sec)	46.9
Maximum Hourly Emissions (lb/hr)[b]:	
SO_2	0.30
PM	1.00
NO_x	13.0
CO	10.0
VOC	4.30
Sulfuric Acid Mist	0.0231
Maximum Annual Emissions (TPY)[b]:	
SO_2	1.32
PM	4.38
NO_x	56.9
CO	43.8
VOC	18.8
Sulfuric Acid Mist	0.101

Note: Neg. = negligible emissions for applicable pollutant.

[a] Based on the duct burner operating for 8,760 hours at 100 MMBtu per hour and the following emission factors:
PM = 0.01 lb/MMBtu; SO_2 = 1 grain/100 cf of natural gas;
NO_x = 0.13 lb/MMBtu; CO = 0.10 lb/MMBtu; VOC = 0.043 lb/MMBtu, and H_2SO_4 = 5% of SO_2

Tables A-13 through A-16 present emissions.

[b] Other regulated pollutants are assumed to have negligible or no emissions.

Table 2-6. Summary of the Annual Emissions for the Proposed Combustion Turbines Operating in Simple and Combined Cycle Modes and Auxiliary Boiler

	Emissions (TPY)[a]							
	Simple Cycle		Combined Cycle--Water Injection			Combined Cycle--Dry Low NO_x		
Pollutant	CT	Total	CT	AB	Total	CT	AB	Total
SO_2	4.76	4.76	9.52	1.32	10.8	9.03	1.32	10.3
PM	21.90	21.90	43.8	4.38	48.2	43.8	4.38	48.2
NO_x[b]	159.1	159.1	318.2	56.9	375.1	304.6	56.9	361.5
CO	117.5	117.5	235.1	43.8	278.9	236.4	43.8	280.0
VOC	16.8	16.8	33.6	18.8	52.4	33.8	18.8	52.6
Sulfuric Acid Mist	0.36	0.36	0.73	0.101	0.83	0.69	0.101	0.79

Note: CT = combustion turbine.
AB = auxiliary boiler.

Simple cycle operation includes one CT. Combined cycle operation includes two CTs and one AB. The CTs and AB are assumed to operate for 8,760 hours per year.

[a] Based on ambient temperature of 59°F.
[b] Based on 25 ppm, corrected to 15 percent O_2 and dry conditions by volume (ppmvd). After December 31, 1997, NO_x emissions will be limited to 15 ppmvd, corrected to 15 percent O_2.

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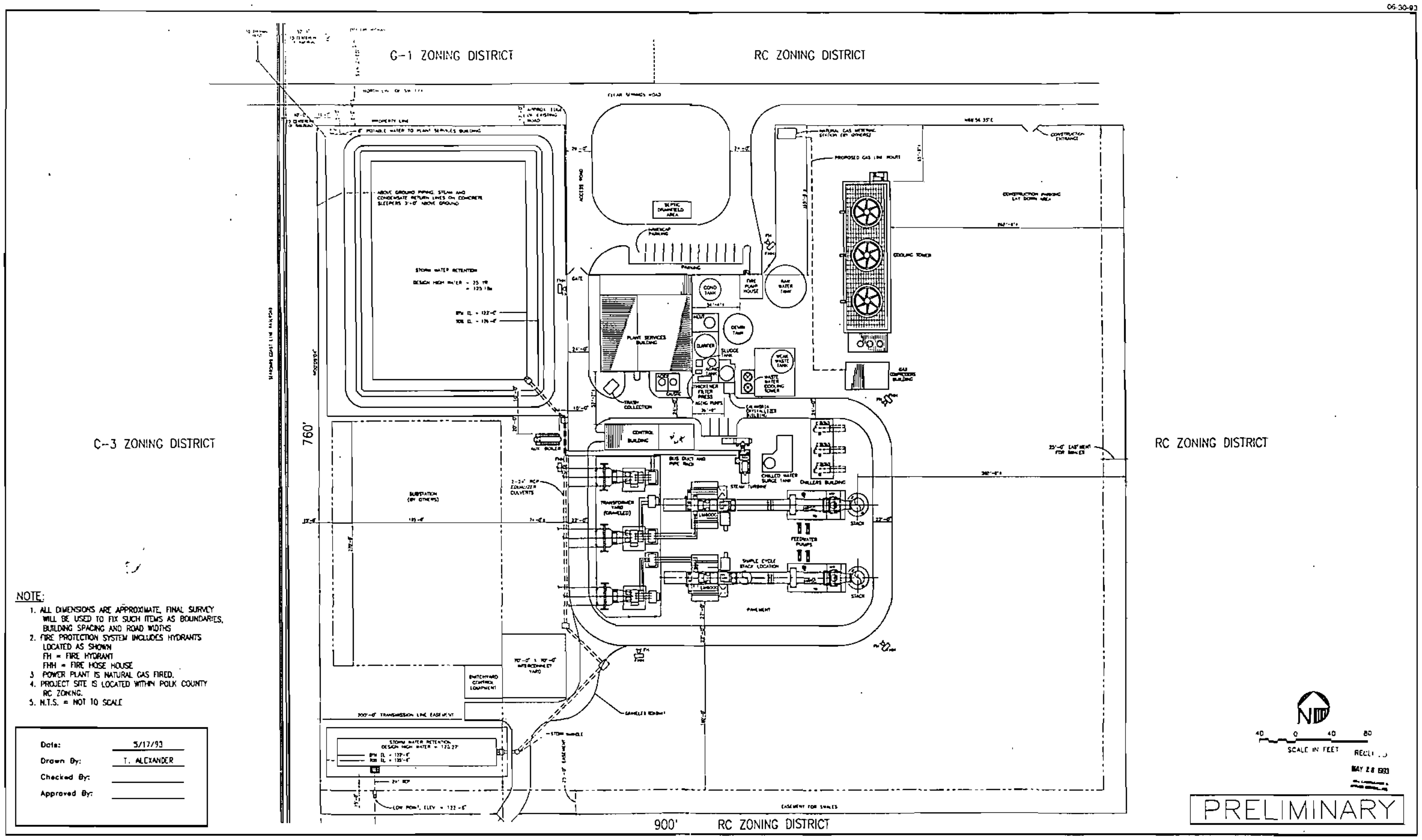

Figure 2-2 SITE LAYOUT

KBN

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed project. These regulations must be satisfied before the proposed facility (combined cycle turbines and auxiliary boilers) can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the Florida Department of Environmental Regulation (FDER).

A "major facility" is defined as any one of 28 named source categories that has the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

		AAQS[a]					
		National		State of Florida	PSD Increments[a]		Significant Impact Levels[b]
Pollutant	Averaging Time	Primary Standard	Secondary Standard		Class I	Class II	
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

[a]Short-term maximum concentrations are not to be exceeded more than once per year.
[b]Maximum concentrations are not to be exceeded.
[c]Proposed October 5, 1989.
[d]Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated, based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks,

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	[c]	NM
Radionuclides	NESHAP	[c]	NM
Inorganic Arsenic	NESHAP	[c]	NM

[a] Short-term concentrations are not be be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration as a result of emissions of NO_x and established PSD increments for NO_2 concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDER has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and

2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.).

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that Best Available Control Technology (BACT) be applied to control emissions from the source [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C., as:

> An emissions limitation, including a visible emission standard, 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 (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT), (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDER may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised). The source impact analysis for criteria pollutants to address compliance with AAQS and PSD Class II increments may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below significance levels, as presented in Table 3-1.

EPA and the National Park Service (NPS) has recommended significant impact levels for PSD Class I areas. The levels are as follows:

Pollutant	Averaging Time	Maximum Significance Level ($\mu g/m^3$)
SO_2	3-hour	1.23
	24-hour	0.275
	Annual	0.1
PM(TSP)	24-hour	1.35
	Annual	0.27
NO_2	Annual	0.1

Although these levels were proposed for use in Virginia and may not be binding in other states, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. EPA's Office of Air Quality Planning and Standards has initiated a motion that will lead to rulemaking to address the general need for Class I significant impact levels. The action is part of EPA's efforts to incorporate new source review provisions of the 1990 Clean Air Act Amendments. Because the process of developing the regulations will be lengthy, EPA believes that immediate guidance concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDER [Chapter 17-2.270, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s); or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

The project site is located in Polk County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Polk County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The site is located approximately 114 km from the closest part of the Chassahowitzka National Wilderness Area.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because emissions of any regulated pollutant will exceed 250 TPY (refer to Table 2-2); therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for PM(TSP), PM(PM10), NO_2, CO, and VOC. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

Based on the net increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for VOCs. However, if the net increase in impact of a pollutant is less than the *de minimis* monitoring concentration (or, for VOCs, *de minimis* emission rate of 100 TPY), then an exemption from the preconstruction ambient monitoring requirement is provided for in the FDER regulations [FDER Rule 17-2.500(3)(e)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data (e.g., FDER) or the collection of on-site data.

Maximum predicted impacts as a result of the net increase associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum net increase in impact is below the respective *de minimis* monitoring concentration for all pollutants.

3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The stacks for the proposed turbine in simple-cycle operation, HRSG, and auxiliary boiler will be 60 feet (ft) (18.3 m), 100 ft (30.5 m), and 65 ft (19.8 m), respectively. These stack heights do not exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.3 NONATTAINMENT REVIEW

The project site is located in Polk County, which is classified as an attainment area for all criteria pollutants. The plant is also located

Table 3-3. Net Increase in Emissions Due To the Proposed Orange Cogeneration Facility Compared to the PSD Significant Emission Rates

	Emissions (TPY)		
Pollutant	Potential Emissions From Proposed Facility[a]	Significant Emission Rate	PSD Review
Sulfur Dioxide	10.8 (WI)	40	No
Particulate Matter (TSP)	48.2 (WI/DLN)	25	Yes
Particulate Matter (PM10)	48.2 (WI/DLN)	15	Yes
Nitrogen Dioxide	375.1 (WI)	40	Yes
Carbon Monoxide	280.0 (DLN)	100	Yes
Volatile Organic Compounds	52.6 (DLN)	40	Yes
Lead	NEG	0.6	No
Sulfuric Acid Mist	0.83 (WI)	7	No
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Asbestos	NEG	0.007	No
Beryllium	NEG	0.0004	No
Mercury	NEG	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	NEG	0	No

Note: NEG = Negligible.
All calculations based on 59°F peak load condition.
WI = water injection
DLN = dry low NO_x

[a] Includes emissions due to two combined cycle CT units and an auxiliary boiler.

Table 3-4. Predicted Net Increase in Impacts Due To the Proposed Orange Cogeneration Facility Compared to PSD *De Minimis* Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$) Predicted Net Increase in Impacts[a]	*De Minimis* Monitoring Concentration
Particulate Matter (TSP)	0.10	10, 24-hour
Particulate Matter (PM10)	3.47	10, 24-hour
Nitrogen Dioxide	0.90	14, annual
Carbon Monoxide	34.8	575, 8-hour
Volatile Organic Compounds (VOCs)	52.6 TPY	100 TPY

Note: TPY = tons per year.

[a] See section 7.0 for air dispersion modeling results. PM/PM10 and NO_2 results are based on combined cycle operation with dry low NO_x combustors at an ambient temperature of 100°F. CO results are based on combined cycle operation with dry low NO_x combustors at ambient temperature of 40°F.

more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has promulgated guidelines (FDER, 1992) to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. Maximum concentrations for all regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to no-threat levels (NTL) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered not to pose a significant health risk. The NTLs for pollutants applicable to the proposed project are presented in Table 3-5. Emissions for these pollutants are presented in Appendix A.

Table 3-5. Summary of Florida No-Threat Levels for Toxic Air Pollutants Applicable to the Proposed Facility Analysis

Pollutant	No-Threat Level (μg/m) 8-Hour	24-Hour	Annual
Formaldehyde	4.5	1.08	0.077
Sulfuric Acid Mist	10	2.38	NE

Note: NE = none established.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of PM10, NO_x, CO, and VOC (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring the top-down approach.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR 60, Subpart GG. These regulations apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.06 percent, the NSPS is increased by 0.0024 percent or 24 parts per million (ppm).

Table 4-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.
[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

For the proposed CTs, the NSPS emission limit would be 112.4 ppm (wet injection) and 115.9 ppm (dry low NO_x) on gas (corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent).

The applicable NSPS for the auxiliary boiler will be 40 CFR 60, Subpart Dc. The applicable requirements are presented in Table 4-2.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY - COMBUSTION TURBINE

4.3.1 NITROGEN OXIDES

4.3.1.1 Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-3 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines. This table was developed from the information contained in the LAER/BACT clearinghouse documents (EPA, 1985b, 1986, 1987c, 1988c, 1989) and by contacting state agencies, such as the California Air Control Board, the South Coast Air Quality Management District, the New Jersey Department of Environmental Protection, and the Rhode Island Department of Environmental Management.

The most stringent NO_x controls for CTs established as LAER/BACT by state agencies are selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. SCR has been installed or permitted in

Table 4-2. Summary of NSPS For Small Industrial-Commercial-Institutional Steam Generating Units

Unit Size (heat input)	Fuel	Annual Capacity Factor	Emission Standard
PARTICULATE MATTER			
30-100 MMBtu/hr	Coal; Coal w/other fuels	>90% on coal	0.05 lb/MMBtu
		<90% on coal	0.10 lb/MMBtu
	Wood; Wood w/other fuels (except coal)	>30% on wood	0.10 lb/MMBtu
		<30% on wood	0.30 lb/MMBtu
	Oil	No limitation	No emission limit
OPACITY			
30-100 MMBtu/hr	All fuels	No limitation	20% opacity
SULFUR DIOXIDE			
>75 MMBtu/hr	Coal	>55% on coal	1.2 lb/MMBtu; 90% reduction
	Coal	<55% on coal	1.2 lb/MMBtu
	Coal w/emerging SO_2 control technology	>55% on coal	0.6 lb/MMBtu; 50% reduction
	Coal in duct burner of combined cycle system	No limitation	1.2 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu; 80% reduction
30-75 MMBtu/hr	Coal	No limitation	1.2 lb/MMBtu
	Coal w/emerging SO_2 control technology	No limitation	0.6 lb/MMBtu
	Coal in duct burner of combined cycle system	No limitation	0.6 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu

Table 4-3. Summary of BACT Determinations for NO_x from Gas-Fired Turbines (Page 1 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Eff. (%)
Tiger Bay Cogen	FL	May-93	GE FA	206 MW	--	97.2	425.7	15 @ 15% O_2	Dry low NO_x burners	--
Central Florida Cogen	FL	Nov-92	GE EA	126 MW	--	87.8	384.5	25 @ 15% O_2	Low NO_x burners and water injection	--
University of Florida Cogen	FL	Aug-92	GE LM6000	43 MW	--	35	142.7	25 @ 15% O_2	--	--
Bermuda Hundred Energy	VA	Mar-92	Gas Turbine	1175 MMBtu/hr	--	--	--	9 ppm @ 15% O_2	SCR/Steam Injection	--
Bermuda Hundred Energy	VA	Mar-92	Gas Turbine	1117 MMBtu/hr	--	--	--	15 ppm @ 15% O_2	SCR/Steam Injection	--
Southern California Gas	CA	Oct-91	GT Solar Model H	5500 HP	--	--	--	8 ppm @ 15% O_2	High Temp SCR	--
Southern California Gas	CA	Oct-91	GT Solar Model H	47.64 MMBtu/hr	--	1.92	--	--	SCR	
El Paso Natural Gas	AZ	Oct-91	GT Solar Centaur H	5500 HP	--	--	--	42 ppm @ 15% O_2	Dry Low NO_x Combustor	--
El Paso Natural Gas	AZ	Oct-91	GT Solar Centaur H	5500 HP	--	--	--	85.1 ppm @ 15% O_2	Lean Fuel Mix	--
El Paso Natural Gas	AZ	Oct-91	GT Solar Centaur H	5500 HP	--	--	--	84.9 ppm @ 15% O_2	Lean Burn	--
El Paso Natural Gas	AZ	Oct-91	GE Gas Turbine	12000 HP	--	--	--	42 ppm @ 15% O_2	Dry Low NO_x Combustor	--
El Paso Natural Gas	AZ	Oct-91	GE Gas Turbine	12000 HP	--	--	--	225 ppm @ 15% O_2	Lean Burn	--
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	25 @ 15% O_2	Steam Injection	--
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	25 @ 15% O_2	Steam Injection	--
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	--	--	--	42 @ 15% O_2	Dry Low NO_x Combustor	--
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	--	6.3	--	40 ppmv @ 15% O_2	Water Inject 0.67 lb/lb	71.00
City of Lakeland	FL	Jul-91	Combined Cycle	120 MW	--	--	--	25 @ 15% O_2	Dry Low NO_x Combustor	--
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	--	--	--	6 @ 15% O_2	SCR	90.00
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	--	--	--	25 @ 15% O_2	Dry Low NO_x Combustor	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	--	139	--	25	H2O Injection & Low NO_x Comb.	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	--	--	1032	42	Water Injection	--
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	--	--	--	42 @ 15% O_2	Wet Injection	--
Salinas River Cogen	CA	Nov-90	Gas Turbine	43.2 MW	--	10	--	6 @ 15% O_2	Dry Low NO_x Comb. & SCR	--
Sargent Canyon Cogen Co	CA	Nov-90	Gas Turbine	42.5 MW	--	10	--	6 @ 15% O_2	Dry Low NO_x Comb. & SCR	--
March Point Cogen	WA	Oct-90	Turbine	80 MW	--	--	--	25 @ 15% O_2	Massive Steam Injection	80.00
Las Vegas Cogen	NV	Oct-90	Turbine, Peaking	397 MMBtu/hr	--	--	--	10 ppm	Water Injection & SCR	--
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	0.10	--	--	25 @ 15% O_2	Dry Low NO_x Combustor	--
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	--	--	--	9	Dry Comb. to 25 ppm, SCR to 9 ppm	--
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	--	--	--	36		--
O'Brian California Cogen II	CA	Jan-90	Gas Turbine	49.50 MW	--	114.6	--	--		--
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	--	--	--	9 @ 15% O_2, 1H Avg	Water Injection & SCR	80.00
Richmond Power Enterprise Partn.	VA	Dec-89	Gas Turbine	1,163.5 MMBtu/hr	--	--	--	8.2 @ 15% O_2	Steam Inj. & SCR	--
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	--	--	--	25 ppm	Steam Injection	--
Badger Creek Limited	CA	Oct-89	GT-Cogen	457.8 MMBtu/hr	0.0135	--	--	--	Steam Injection & SCR	--
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	--	--	--	42 @ 15% O_2	Steam Injection	--
City of Anaheim GT Proj.	CA	Sep-89	Gas Turbine	442 MMBtu/hr	--	3.75	--	--	Steam Injection & SCR	69.60

Table 4-3. Summary of BACT Determinations for NO_x from Gas-Fired Turbines (Page 2 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Eff. (%)
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.17	83	--	--	Water Injection	--
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	--	--	--	36 ppm	Water Injection	--
Cimarron Chemical Co.	CO	Aug-89	Turbines (2)	271.0 MMBtu/hr	--	--	--	65 ppmv @ 15% O_2	Steam Injection	--
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	--	--	--	42 ppm	Steam Injection	--
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	--	--	--	42 ppm	Water Injection	--
Potomac Electric Power Company	MD	Mar-89	Combined Cycle	860 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	--	--	--	42 @ 15% O_2	Water Injection	--
Pawtucket Power	RI	Jan-89	Turbine	58 MW	--	--	--	9 @ 15% O_2	SCR	--
L&J Energy System Cogen	NY	Jan-89	GE LM 5000	40 MW	--	--	--	42 ppm	Steam Injection	--
Mojave Cogen	CA	Jan-89	Turbine	490 MMBtu/hr	0.031	--	--	--	--	--
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	--	--	--	9 @ 15% O_2	Water Injection & SCR	--
Mojave Cogen	CA	Dec-88	Turbine	45 MW	--	--	--	10 ppm	Steam Injection & SCR	--
Champion International	AL	Nov-88	Gas Turbine	35 MW	--	--	--	42 @ 15% O_2	Steam Injection	70.00
Indeck-Yerks Energy Services	NY	Nov-88	GE Frame 6	40 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	--	--	--	55 ppm	Water Injection	--
Amtrak	PA	Oct-88	Turbine (2)	20 MW	--	--	--	42 @ 15% O_2	H_2O Injection	--
Mobile Oil	CA	Sep-88	Turbine (2)	81.40 MMBtu/hr	0.047	3.78	--	--	Water Inj. & SCR	--
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	--	--	--	42 ppm	Steam Injection	--
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	--	--	--	42 ppm	Low NO_x Burners & Water Inj.	--
O'Brien Cogen	CT	Aug-88	Gas Turbine (2)	499.9 MMBtu/hr	--	--	--	39 @ 15% O_2	Water Injection	--
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	--	--	--	42 ppm	Steam Injection	--
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	--	--	--	42 @ 15% O_2, 1H Avg	H20 Injection	59.00
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	--	--	--	36 @ 15% O_2	Water Injection	--
Merck Sharp & Pohme	PA	May-88	Turbine	310 MMBtu/hr	--	--	--	42 @ 15% O_2	Steam Injection	--
Virginia Power	VA	Apr-88	GE Turbine	1,875 MMBtu/hr	--	490		42 @ 15% O_2	Steam Injection	--
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.2	--	--	75 ppm	H_2O Inj. & Combustion Controls	--
Combined Energy Resources	CA	Feb-88	Gas Turbine	25.94 MW	--	199.0	--	--	H_2O Injection & SCR	81.00
Texas Gas Transmission Corp.	KY	Feb-88	Gas Turbine	14300 HP	--	--	--	--	NO_x 0.015 % by Volume	--
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBtu/hr	--	--	--	42 @ 15% O_2	Steam Injection	--
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	--	85	--	--	Water Inj. & Quiet Combustion	--
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	--	--	--	42 @ 15% O_2	Water Injection	--
BAF Energy	CA	Jul-87	Turbine, Generator	887.2 MMBtu/hr	--	30.1	--	9 ppm @ 15% O_2	Steam Injection & SCR	80.00
AES Placerita, Inc.	CA	Jul-87	Turbine	530 MMBtu/hr	--	14.2	--	9 @ 15% O_2	St./F Ratio 2.2:1 & SCR	--
AES Placerita, Inc.	CA	Jul-87	Gas Turbine	530 MMBtu/hr	--	12.0	--	9 @ 15% O_2	St./F Ratio 2.2:1 & SCR	--
Simpson Paper Co.	CA	Jun-87	Gas Turbine	49.50 MW	--	9.71	--	6 @ 15% O_2	Steam Injection & SCR	--

Table 4-3. Summary of BACT Determinations for NO_x from Gas-Fired Turbines (Page 3 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Eff. (%)
Power Development Co.	CA	Jun-87	Gas Turbine	49 MMBtu/hr	--	1.5	--	9 @ 15% O_2	H_2O Injection & SCR	--
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	--	10.4	--	6 @ 15% O_2	H_2O Injection & SCR	76.00
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	--	--	--	9.6 @ 15% O_2	H_2O Injection & SCR	95.00
Trunkline LNG	LA	May-87	Gas Turbine	147,102 SCF/hr	--	59		--	--	--
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	--	50.3	--	154	Combustion Control	--
Anheuser-Busch	FL	Apr-87	Gas Turbine	95.7 MMBtu/hr	0.10	--	--	--	--	--
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW	--	--	--	75 @ 15% O_2	H_2O Injection	--
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	--	--	--	--	--	--
U.S. Borax & Chemical Corp.	CA	Feb-87	Gas Turbine	45 MW	--	40	--	25 ppm @ 15% O_2	Proper Combust. Techniques	--
Sierra LTD.	CA	Feb-87	GE Gas Turbine	11.34 MMCF/D	0.016	4.04	--	--	Steam Injection & SCR	95.86
Midway-Sunset Project	CA	Jan-87	Gas Turbines (3)	973 MMBtu/hr	--	113.4	--	16.31 ppmv	H_2O Injection	73.00
City of Santa Clara	CA	Jan-87	Gas Turbine	--	--	--	--	42 @ 15% O_2	Water Injection	--
O'Brien NRG Systems/Merchants Ref	CA	Dec-86	Gas Turbine	359.5 MMBtu/hr	--	30.3	--	15 @ 15% O_2	Water Injection & SCR	--
California Dept. of Corr.	CA	Dec-86	Gas Turbine	5.1 MW	--	--	--	38 @ 15% O_2	1:1 H_2O Injection	--
Double 'C' Limited	CA	Nov-86	Gas Turbine	25 MW	--	8.08	--	--	H_2O Inj. & Selected Catalytic Red.	--
Kern Front Limited	CA	Nov-86	Gas Turbine (2)	50 MW	--	8.08	--	4.5 @ 15% O_2	Water Injection & SCR	95.80
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBtu/hr	--	63	--	25 ppm @ 15% O_2	Steam Injection @ St/F Ratio of 1.7/1	75.00
Wichita Falls E. I., I.	TX	Jun-86	Gas Turbine	20 MW	--	--	684	--	Steam Injection	--
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	--	--	640	--	Steam Injection	--
Kern Energy Corp.	CA	Apr-86	Gas Turbine	8.8 MMCF/D	0.023	8.29	--	--	Steam Inj., Low NO_x Config. & SCR	87.00
Monarch Cogen	CA	Apr-86	Combined Cycle	92.20 MMBtu/hr	--	8.02	--	22 @ 15% O_2	SCR	--
Moran Power, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.02	8.29	--	--	Steam Inj., Low NO_x Config. & SCR	87.00
Southeast Energy, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.023	8.29	--	--	Steam Inj., Low NO_x Config. & SCR	87.00
Western Power System, Inc	CA	Mar-86	GE Gas Turbine	26.5 MW	--	--	--	9 @ 15% O_2	H_2O Injection & SCR	80.00
AES Placerita, Inc.	CA	Mar-86	Turbine	519 MMBtu/hr	--	26.2	--	7 @ 15% O_2	H_2O Injection & SCR	--
OLS Energy	CA	Jan-86	GE Gas Turbine	256 MMBtu/hr	--	--	--	9 @ 15% O_2	H_2O Injection & Scrubber	80.00
Union Cogeneration	CA	Jan-86	Gas Turbine	16 MW	--	--	--	25 @ 15% O_2	H_2O Injection & Scrubber	--

about 132 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About 83 percent (i.e., 109) of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, 43 percent have been in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

As noted previously, there are distinct regulatory and policy differences between LAER and BACT.

All the projects in California have natural gas as the primary fuel, and only 15 of the SCR applications in California have distillate fuel as backup.

The remaining projects with SCR (i.e., 23 projects) are located in the eastern United States. These projects are located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with 87 percent less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent. The most stringent emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, two facilities have reported emission limits of about 4.5 ppm. These emission limits were clearly determined to be LAER on CTs using water injection with uncontrolled NO_x levels below 42 ppm. SCR has not been installed or permitted on simple cycle CTs.

Wet injection has been the primary method of reducing NO_x emissions from CTs. This method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when burning natural gas. More recently, CT manufacturers have developed dry low-NO_x combustors that can initially reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when firing natural gas; retrofitting with improved combustors will achieve 15 ppmvd.

In Florida, a majority of the most recent PSD permits and BACT determinations for gas turbines have required either wet injection or dry low-NO_x technology for NO_x control. The emission limits included in these latest permits and BACT determinations are 25/15 ppmvd corrected to 15 percent O_2 for natural-gas firing using combustion technology. These permits require that sources meet 15 ppmvd by December 31, 1997.

4.3.1.2 <u>Technology Description and Feasibility</u>

<u>Selective Catalytic Reduction (SCR)</u>--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle CTs generally are in the range of 800°F to 1,000°F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 4-4.

As presented in Table 4-4, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°F to 950°F, have been available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines which have relatively high NO_x emissions (i.e., 7,500 ppm) and low flow rates. Optimum performance of an SCR system using

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems, such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates backpressure on theturbine, which reduces overall heat rate.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x before to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within (i.e., about 100°F) must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 2 of 2)

Consideration	Description
Ammonia Control	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip (NH_3 that passes unreacted through the catalyst and into the atmosphere) can occur if 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can occur when firing natural gas. These compounds are emitted as particulates.
Ammonia Transportation and Storage	Storage and handling of anhydrous ammonia produces additional environmental risks. Appropriate controls and contingency plans in the event of a release is required.

a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,000°F and above, the zeolite catalyst will be irreparably damaged. Therefore, application of an SCR system using a zeolite catalyst on a simple cycle operation is technically infeasible without exhaust gas cooling. Moreover, since zeolite catalysts have not been operated continuously in combustion exhausts greater than 900°F, the cooling system would have to reduce turbine exhaust temperatures about 200°F (i.e., to around 700°F).

<u>Wet Injection</u>--The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

<u>Dry Low-NO_x Combustor</u>--In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on machines manufactured by GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition.

<u>NO_xOUT Process</u>--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F.

In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75-MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

<u>Thermal $DeNO_x$</u>--Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal $DeNO_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal $DeNO_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of construction-specified material, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal $DeNO_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of a combustion turbine is typically about 1,000°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

Summary of Technically Feasible NO_x Control Methods--The available information suggests that SCR with dry low-NO_x combustor technology or with wet injection would produce the lowest NO_x emissions and is technically feasible. Dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is a technically feasible alternative for the project.

A technical evaluation of other tail gas controls (i.e., NO_xOUT, Thermal DeNO_x, and NSCR) indicates that these processes have not been applied to CT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the CT being considered for the project, the combustion chamber design includes the initial use of wet injection with a retrofit to dry low-NO_x/wet combustor technology. The NO_x emission level guaranteed by GE for the project is 25 ppmvd (corrected to 15 percent O_2) for wet injection and 15 ppmvd (corrected) for the retrofit.

For the BACT analysis, SCR with dry low-NO_x combustion is capable of achieving a NO_x emission level of 9 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions). Combustion controls (i.e., wet injection and/or dry low-NO_x combustion) alone can achieve 25 ppmvd (corrected) and 15 ppmvd, respectively.

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12), Chapter 17-2.100(25), F.A.C., and Chapter 17-2.500(5)(c), F.A.C.]. The analysis must, by definition, be specific to the project (i.e., case-by-case).

The BACT analysis was performed for the following alternatives:

1. SCR and combustion controls at an emission rate of approximately 9 ppmvd corrected to 15 percent O_2 when firing gas; and
2. Combustion controls (i.e., wet injection and/or dry low NO_x) at emission rates of 25 ppmvd corrected to 15 percent O_2 until December 31, 1997 and 15 ppmvd (corrected) thereafter.

The NO_x removed using SCR under this assumption would be 207 TPY when firing natural gas (i.e., at 25 ppmvd). After the first 2 years of operation (i.e., after 1 year of simple cycle operation), the emission rate would be reduced by 40 percent to 15 ppmvd. Under this operational scenario, approximately 120 TPY of NO_x would be removed with SCR. In order to calculate a cost effectiveness over a 20-year period (i.e., the basis for the economic analysis), the cost effectiveness was weight-adjusted by the number of years under the specific operation scenario; i.e., 2 years at 25 ppmvd and 17 years at 15 ppmvd--the first year would be operating on simple cycle.

Economic--The total capital and annualized costs for SCR are presented in Tables 4-5 and 4-6, respectively. The total annualized cost of applying SCR with dry low-NO_x combustion is $1,648,000. The incremental reduction in NO_x emissions is 207 TPY for the first 2 years of combined cycle operation and about 120 TPY thereafter. The incremental cost effectiveness of SCR over water injection is estimated to be $7,970/ton of NO_x removed for the first 2 years of combined cycle operation and $23,510/ton of NO_x removed thereafter. The average cost effectiveness over the initial 20-year period would be $21,900/ton of NO_x removed.

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	559,200	Developed from manufacturer budget quotations[a]
Ammonia Storage Tank	138,400	Developed from manufacturer budget quotations[b]
HRSG Modification	243,600	Developed from manufacturer budget quotations[c]
Indirect Capital Costs		
Installation	351,100	20% of SCR associated equipment and catalyst[d]
Engineering, Erection Supervision, Startup, and O&M Training	248,800	10% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG costs, installation labor[e]
Project Support	136,900	5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs, and installation labor[f]
Ammonia Emergency Preparedness Program	19,200	Engineering estimate
Liability Insurance	13,700	0.5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs and installation labor
Interest During Construction	436,100	15% of all direct and indirect capital costs, including catalyst cost[g]
Contingency	268,200	15% of all capital costs[h]
Total Capital Costs	2,415,300	Sum of all capital costs

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Annualized Capital Costs</u>	283,700	Capital recovery of 10% over 20 years, 11.74% per year[i]
<u>Recurring Capital Costs</u>		
SCR Catalyst (Materials and Labor)	1,196,000	Developed from manufacturer budget quotations[j]
Contingency	179,400	15% of recurring capital costs[k]
<u>Total Recurring Capital Costs</u>	1,375,400	Sum of recurring capital costs
<u>Annualized Recurring Capital Costs</u>	553,100	Capital recovery of 10% over 3 years, 40.21% per year[l]

Note: HRSG = heat recovery steam generators.
SCR = selective catalytic reduction.

Footnotes for Table 4-5

Note: All calculations rounded to nearest 100.

a. Developed from various vendor data as an algorithim to account for mass flow (lb/hr) through HRSG.

The SCR associated cost is made up of 2 factors:

1. Catalyst Housing, vaporizer, and HRSG wash system is $98.7 per 1,000 lb/hr mass flow at ISO (59°F) conditions.

   $\$98.7 \times 996.7 \times 10^3$ lb/hr x 2CTs = $235,300

2. Control system costs = $362,500

   Total is $559,200

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-5 (continued)

b. Ammonia tank size is based on SCR size as follows:

$69.45/1,000 lb mass flow x 996.7 x 10^3 lb/hr x 2CTs = $138,400

c. HRSG modifications based on mass flow at $122.2 per 1,000 lb mass flow.

$122.22/$10^3$ lb x 996.7 x 10^3 lb/hr x 2 CTs = $243,600

d. From EPA OAQPS cost control manual

($559,200 + $1,196,000) x 0.2 = $351,100

e. From EPA OAQPS cost control manual

($559,200 + $138,400 + $1,196,000 + $243,600 + $351,100) x 0.10

= $248,800

f. Engineering estimate; same as engineering costs except use 0.05.

g. From OAQPS cost control manual and engineering estimate.

0.15 x ($559,200 + $138,400 + $243,600 + $351,100 + $248,800

+ $136,900 + $19,200 + $13,700 + $1,196,000) = $436,100

h. From EPA OAQPS cost control manual and engineering estimate

0.20 x ($559,200 + $138,400 + $243,600 + $351,100 + $248,800

+ $136,900 + $19,200 + $13,700 + $436,100 - (0.15 x 0.30

x $1,196,400)

= $268,200; note that the (0.15 x 0.30 x $1,196,400)

removes contingency for catalyst.

i. OAQPS cost control manual; standard statistical tables for 10% interest over 20 years

$2,415,300 x 0.1174 = $283,700

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-5 (continued)

j. Developed from manufacturer data at $0.6/lb mass flow:

$0.6 x 996,700 x 2 = $1,196,000

k. Same rationale as h:

0.25 x $1,196,000 = $179,400

l. Manufacturer guarantees of 3 years life or catalyst. Used OAQPS cost control manual interest of 10 percent over 3 years (40.21 percent per year):

0.4021 x $1,375,400 = $553,100

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	15,600	16 hours/week @ $25/hour[a]
Ammonia	22,900	$300/ton; $NH_3:NO_x$ = 1:1 volume[b]
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ $75/hour plus expenses @ 35% labor[c]
Inventory Cost	46,800	Capital recovery (11.74%/year) for 1/3 of catalyst cost[d]
Catalyst Disposal Cost	55,400	Engineering estimate[e]
Contingency	43,900	25% of indirect costs[f]
Energy Costs		
Electrical	35,000	80 kWh/hr; $0.05/kWh[g]
Heat Rate Penalty	173,000	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh[h]
MW Loss Penalty	167,800	84 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $2.25/MMBtu subtracted[i]
Fuel Escalation Costs	94,600	Real cost increase of fuel [j]
Contingency	45,400	15% of energy costs; excludes fuel escalation[k]
Total Direct Annual Costs	708,500	Sum of all direct annual costs

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Indirect Annual Costs		
Overhead	26,900	60% of ammonia and 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)[l]
Property Taxes and Insurance	75,800	2% of total capital costs[m]
Annualized Capital Costs	283,700	Capital recovery of 10% over 20 years, 11.74% per year (from Table 4-5)
Recurring Capital Costs	553,100	Capital recovery of 10% over 3 years, 40.21% per year (from Table 4-5)
Total Indirect Annual Costs	939,500	Sum of all indirect annual costs
Total Annual Costs	1,648,000	Total annualized cost[n]

Note: All calculations rounded to the nearest $100.

kW = kilowatt.
kWh = kilowatt-hour.
kWh/hr = kilowatt-hour per hour.
MM/Btu = million British thermal units.
NH_3 = ammonia.
NO_x = nitrogen oxides.
O&M = operation and maintenance.

Footnotes for Table 4-6

Note: all calculations rounded to nearest 100

a. Engineering Estimate:

12 hours/week x 52 weeks/year x $25/hour = $15,600

b. Delivered cost of ammonia at $300/ton

207 TPY removed x $300 x 17/46 (molecular weight of ammonia to NO_x)

= 22,900

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 3 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-6 (continued)

c. 80 hours/yr x $75 x 1.35 = $8,100

d. Required to purchase and store 1/3 of a catalyst for replacement or required.

$1,196,000 x 0.1174 (20 years @ 10 percent) + 3 = $46,800

e. Estimated as $27.77/1,000 lb mass flow; based on catalyst volume.

$27.77 x 996.7 (1,000 lb mass flow) x 2CTs = $55,400

f. OAQPS cost control manual background documents

0.25 x ($15,600 + $22,900 + $8,100 + $46,800 + $55,400) = $43,900

g. 40 kWh/hr per system; 2 CTs; $0.05/kWh is cost of estimated energy:

40 kWh/hr x $8,760 hr/yr x $0.08/kWh x 2 CTs = $35,000

h. 4" back pressure from SCR manufacturer; 0.8 percent energy loses from general CT performance curver; 39.49 MW power per CT rating at 150 (59°F) conditions.

39.49 MW x 0.005 x 8,760 hrs/yr x 1,000 kW/mw x $0.05/kWh x 2CTs = $173,000

i. 3 days required to change catalyst or maintenance; saving in gas usage subtracted

39.49 MW x 3 days x 24 hours x $0.05/kWh x 1,000 MWh x 2CTs
- (359.8 x 10^6 Btu/hr x 2CTs x 3 days x 24 hours x $2.25/$10^6$ Btu)
= $167,800

j. Escalation of fuel costs over inflation; 3 percent over 20 years; factor calculated as 0.454565; applies to electrical and heat rate costs only:

0.454565 x ($35,000 + $167,800) = $94,600

k. OAQPS cost control manual background documents

0.15 x ($35,000 + $167,800 x $ 173,000) = $45,400

l. 0.6 ($22,900 + 1.15 x $15,600) + 0.15 x $15,600 = $26,900

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-6 (continued)

m. From OAQPS cost control manual

0.02 x ($2,415,300 + $1,375,400) = $75,800

n. Total direct annual costs plus total indirect annual costs:

$811,200 + $939,500 = $1,648,000

<u>Environmental</u>--The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO_x of 25 $\mu g/m^3$, annual average, and the AAQS for NO_x, 100 $\mu g/m^3$. Indeed, the impacts are less than the significant impact levels. Additional controls beyond wet/dry low-NO_x combustors (i.e., SCR and SCR with water injection) would further reduce predicted impacts by much less than 1 percent of the PSD increment and the AAQS for the project.

The use of wet/dry low-NO_x combustor technology is truly "pollution prevention". In contrast, use of SCR on the proposed project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be 10 ppm based on reported experience; previous permit conditions have specified this level. Ammonia emissions could be as high as 53 TPY. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM10; up to 13.4 TPY could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will generate secondary emissions since this lost energy will necessitate additional generation. These emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-7, which shows the emissions balance for the project with and without SCR. Emissions of carbon dioxide were included in this table since this gas is under study as required in the 1990 Clean Air Act Amendments. As noted from this table, the emissions would be greater with SCR than that proposed using wet/dry low-NO_x combustion technology. Indeed, when emissions of CO_2 are included, the environmental impacts favor the use of combustion controls.

The replacement of the SCR catalyst will create additional environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261).

Table 4-7. Comparison of NO_x Emissions for Combustion Turbines

Type of CT	Size (MW)	Rate (Btu/kwh)	NO_x Emissions @ 25 ppm (lb/hr)	(lb/MW)	Increase From LM6000	Equivalent Emission (ppm)	Equivalent Emission (ppm)
GE 7EA	82.0	10,590	87.8	1.07	16.4%	25.0	15
GE 7FA	151.9	9,750	148.5	0.98	6.4%	22.8	13.7
GE LM6000	39.5	9,111	36.3	0.92		21.5	12.9

Source: GE Data Sheets for the CT listed. All data at ISO conditions except for GE 7FA which was for 64°F.

The use of ammonia is necessary for the reduction of NO_x emissions by means of a catalytic reaction. This process will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has a number of potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (section 112), OSHA 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

Ammonia is a colorless gas with a sharp, pungent odor which can be identified at about 5 ppm. It is lighter than air and very soluble in water. Other chemical and physical properties include:

Molecular weight - 17.03
Density (gas) - 0.5967, (liquid) 0.67
Boiling point - (-33.35°C)
Freezing point - (-77.7°C)
Vapor pressure(liquid) - 8.5 atmospheres at 20°C
Solubility - very soluble in water, alcohol, and ether
Flammable limits in air - LEL 15 percent, UEL 28 percent

Elevated temperatures may contribute to instability and cause containers to burst. Ammonia is incompatible with strong oxidizers, calcium, hypochlorite bleaches, gold, mercury, halogens, and silver. Liquid ammonia will corrode some forms of plastic, rubber, and coatings.

The toxicology of ammonia is well understood from a variety of animal and human studies. Ammonia is a severe irritant of the eyes, especially the cornea, the respiratory tract, and the skin. It is detectable at about 5 ppm and causes respiratory irritation in humans above 25 ppm. The irritating effects of ammonia are less noticeable with chronic exposure. There is at least one reference in the literature that indicates exposure to ammonia and amines increases the incidence of cancer.

The eyes are generally the organ of most concern in an acute exposure. As a strong alkali, ammonia can cause severe burns of the cornea and the effects are often delayed. Even burns that at the time of injury appear to be mild can go on to opacification, vascularization, and ulceration or perforation. Of all the alkali compounds that cause eye damage, ammonia penetrates the cornea the most rapidly, resulting in potentially severe damage to the cornea.

Because ammonia is very soluble in water, it is irritating to the upper respiratory tract. Inhalation of the gas will cause throat and nose irritation and dyspnea as aqueous ammonia is formed. Liquid anhydrous ammonia will cause first and second degree burns on contact with the skin. Standards applicable to ammonia are listed below:

OSHA--35 ppm as a 15-minute short-term exposure limit (STEL), 29 CFR 1910.1000.

ACGIH/NIOSH--25 ppm as an 8-hour TWA, 35 ppm as a 15-minute STEL.

NIOSH has also established an immediately dangerous to life or health (IDLH) recommendation of 500 ppm. The U.S. Navy has established a limit of 25 ppm for continuous exposure to personnel in submarines.

Employee exposure to ammonia should be measured on a regular basis to assure compliance with the applicable standards and verify that the protective equipment chosen is effective. Monitoring should follow the procedures outlined in the NIOSH Manual of Analytical Methods, Number 6701. Air-purifying respirators may be used if concentrations do not exceed 250 ppm. If concentrations exceed 250 ppm, a supplied air system must be used to provide maximum protection. The use of any respirator requires the implementation of a respiratory protection program in compliance with 29 CFR 1910.134.

Protective clothing should be provided to employees if there is any chance of skin or eye contact with solutions of more than 10 percent ammonia. Protective clothing includes goggles or face shields for face and eye protection and impervious clothing. Facilities should be provided for quick drenching of the skin and eyes of employees exposed to ammonia.

The utilization of ammonia will require the installation of one or more pressure vessels (anhydrous ammonia) or atmospheric tanks (aqueous ammonia). OSHA, in 29 CFR 1910.119, requires a stringent process safety review if 10,000 pounds of anhydrous ammonia or 15,000 pounds of aqueous ammonia (> 44 percent ammonia by weight) is stored in one location at the site. Compliance with the standard requires the preparation of a process safety analysis that is updated every 5 years. Other major requirements include: written operating procedures, employee training, pre-startup review, mechanical integrity checks, hot work permit system, incident investigation (releases), emergency action plan, and a compliance audit every 3 years.

Section 112 of the 1990 Clean Air Act Amendments proposes to regulate a number of highly toxic substances. Anhydrous and aqueous ammonia are both listed as compounds that may cause a threat to the public if released to the atmosphere. Regulated facilities must prepare a risk management plan which shall include a hazard assessment to predict the effect of any release. Other requirements include the development of worst-case release scenarios, training, monitoring, and actions to be taken in the event of a spill.

Energy--Energy penalties will occur with all control alternatives evaluated. However, significant energy penalties occur with SCR. With SCR, the output of the CT is reduced by about 0.50 percent over that of wet injection. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 3,460,000 kilowatt hours (kWh) in potential lost generation per year. The energy required by the SCR equipment would be about 700,800 kilowatt hours per year (kWh/yr). Taken together, the lost generation and energy requirements of SCR could supply the electrical needs of 300 residential customers. To replace this lost energy, an additional 4 x 10^{10} British thermal units per year (Btu/yr) or about 40 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--The project will use an advanced air craft derivative gas turbine with wet/dry low-NO_x combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design will be wet injection with retrofitting dry low-NO_x combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects to the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

The LM6000 machine is unique from an engineering perspective in two ways. First, the combination of advanced aircraft derivative compressor and turbine sections results in a more thermally efficient machine with a heat rate of 9,111 Btu/kWh at ISO conditions. In contrast, large industrial combustion turbines have heat rates between 10,600 Btu/kWh (conventional) and 9,800 Btu/kWh (advanced frame). This has the added advantage of producing lower air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated.

The second unique attribute of the proposed CT will be the use of wet/dry low-NO_x combustors that will reduce NO_x emissions to 15 ppmvd corrected to 15 percent oxygen by December 31, 1997. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air are premixed prior to ignition. This level of control has never before been achieved in an advanced CT and will result in emissions of less than 0.1 lb/10^6 Btu, which is more than two times lower than emissions from conventional steam generators.

Since the purpose of the project is to produce electrical energy, and combustion turbine technology is rapidly advancing, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT and advanced CT. The heat rate of an advanced GE Frame

7FA will be 9,750 Btu/kWh at ISO conditions, and the heat rate for the conventional GE Frame 7EA is 10,590 Btu/kWh (see Table 4-7).

Therefore, the NO_x emissions for the LM6000 will be 16 percent less than a conventional CT and 6 percent less than an advanced CT for the same amount of generation.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the project is wet and dry low-NO_x combustion technology. When firing natural gas, the proposed NO_x emissions level using this technology is initially 25 ppmvd (corrected to 15 percent oxygen) for the first 2 years of combined cycle operation and 15 ppmvd (corrected) thereafter. This control technology is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. The estimated incremental cost of SCR is more than $20,000 per ton of NO_x removed. These costs are clearly above the range for other projects that have rejected SCR as unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered (refer to Table 4-8). SCR is not cost effective when the emissions (exclusive of CO_2) are considered.
2. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary generations (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst replacement).
3. The energy impacts of SCR will reduce potential electrical power generation by more than 4 million kWh.
4. The proposed BACT (i.e, wet and dry low-NO_x combustion) provides the most cost effective control alternative and results in low environmental impacts (less than the significant impact levels). Wet/dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations. In addition, CT

Table 4-8. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

Pollutants	Project With SCR Primary	Project With SCR Secondary[a]	Project With SCR Total	Project Without SCR CT/DB	Difference[b]
Particulate	13.4 [c]	2.1	15.5	0	15.5
Sulfur Dioxide	0	23.1	23.1	0	23.1
Nitrogen Oxides	120.0 [d]	11.5	131.5	204.3 [e]	(-72.8)
Carbon Monoxide	0	0.7	0.7	0	0.7
Volatile Organic Compounds	0	0.1	0.1	0	0.1
Ammonia	52.7 [f]	0.00	52.7	0	52.7
Total	186.1	37.5	223.6	204.3	19.3
Carbon Dioxide[g]	--	3,606	3,606	--	3,606

Note: Btu/kWh = British thermal units per kilowatt-hour.
CT = combustion turbine.
DB = duct burner.
MW = megawatt.
% = percent.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Lost energy of 0.48 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 79.88 MW plus 0.080 MW). Assumes Florida Power Corp. baseloaded oil-fired unit would replace lost energy. EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh. Emission factors use were (lb/10^6 Btu): PM = 0.1; SO_2 = 1.1; NO_x = 0.55, CO = 0.033 and VOC = 0.005. Example calculation for PM: 0.48 MW x 10,000 Btu/kwh x 1,000 kw/MW x 8,760 hr/yr x 0.1 lb PM/10^6 Btu ÷ 2,000 lb/ton = 2.10 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 17 TPY H_2SO_4 x 132 (MW of ammonia salt) ÷ 98 (MW of H_2SO_4).

[d] 9 ppm NO_x emissions on gas.

[e] Weighted average emission; 25 ppm for first 2 years and 15 ppm for 17 years.

[f] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 292,495 acfm/CT x 60 m/hr x 10 ppm/10^6 x 2,116.8 lb/ft^2 ÷ 1,545 x 17 (molecular weight of NH_3) ÷ (460 + 220) x 8,760 ÷ 2,000 x 2 CTs.

[g] Reflects differential emissions due to lost energy efficiency with SCR (i.e., 0.48 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 Btu/lb).

manufacturers have been willing to guarantee this level of NO_x emissions.

4.3.2 CARBON MONOXIDE

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table 4-9 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. For the CT being evaluated, CO emissions will not exceed 30 ppmvd, corrected to dry conditions when firing natural gas under full load conditions.

Catalytic oxidation is a post-combustion 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).

4.3.2.2 Technology Description

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 CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas.

Table 4-9. Summary of BACT Determinations for CO from Gas-Fired Turbines (Page 1 of 2)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Eff. (%)
Tiger Bay Cogen	FL	May-93	GE FA	206 MW	--	48.8	213.7	15 @ 15% O_2	Proper combustion	--
Central Florida Cogen	FL	Nov-92	GE EA	126 MW	--	42.9	187.8	20 @ 15% O_2	Efficient combustion	--
University of Florida Cogen	FL	Aug-92	GE LM6000	43 MW	--	38.8	158	42 @ 15% O_2	--	--
Bermuda Hundred Energy	VA	Mar-92	Gas Turbine	1175 MMBtu/hr	62	--	--	--	Furnace Design	
Bermuda Hundred Energy	VA	Mar-92	Gas Turbine	1117 MMBtu/hr	62	--	--	--	Furnace Design	
Southern California Gas	CA	Oct-91	GT Solar Model H	47.64 MMBtu/hr	--	--	--	7.74 ppm @ 15%	High Temp Oxidation Catalyst	--
El Paso Natural Gas	AZ	Oct-91	GT Solar Centaur H	5500 HP	--	--	--	10.5 ppm @ 15%	Lean Fuel Mix	--
El Paso Natural Gas	AZ	Oct-91	GE Gas Turbine	12000 HP	--	--	--	60	Lean Burn	--
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	42	78 ppmvd for oil firing	--
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	42	78 ppmvd for oil firing	--
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	--	--	--	--	25 ppmvd for oil firing	--
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	--	5.8	--	60 @ 15% O_2	Base Case, No Additional Control	--
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	--	--	--	6 @ 15% O_2	CO Catalyst	80.00
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	--	--	--	30	33 ppmvd for oil firing	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	--	--	261	30	Combustion control	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	--	--	261	30	Combustion control	--
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	--	--	--	30	33 ppmvd for oil firing	--
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	--	--	--	10	26 ppmvd for oil firing	--
March Point Cogen	WA	Oct-90	Turbine	80 MW	--	--	--	37 @ 15% O_2	Combustion Control	--
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	--	--	--	15 ppm	Good Combustion	--
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	--	25	--	--	Combustor Design & Operation	--
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	0.02	--	--	--	--	--
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	--	--	--	50 @ ISO Cond & 12% O_2	Design & Good Combustion Techniques	--
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	--	--	--	25 ppm	Combustion Control	--
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	0.112	--	--	--	--	--
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.022	10.8	--	--	Combustion Control	--
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	0.028	--	--	--	Combustion Control	--
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	--	--	--	10 @ 15% O_2	--	--
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	0.024	--	--	--	Combustion Control	--
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	0.026	--	--	--	Combustion Control	--
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	0.022	--	--	--	Combustion Control	--
Pawtucket Power	RI	Jan-89	Turbine	58 MW	--	--	--	23 @ 15% O_2	--	--
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	--	--	--	25 @ 15% O_2	--	--
Champion International	AL	Nov-88	Gas Turbine	35 MW	--	9	--	--	--	--
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	--	--	--	10 ppm	Combustion Control	--
Amtrak	PA	Oct-88	Turbine (2)	20 MW	--	30.76	--	--		
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	0.021	--	--	--	Combustion Control	--

Table 4-9. Summary of BACT Determinations for CO from Gas-Fired Turbines (Page 2 of 2)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Eff. (%)
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	--	--	--	10 @ 15% O_2	Combustion Control	--
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	--	--	--	15 ppm	Good Combustion	--
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	0.022	--	--	--	Combustion Control	--
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	0.1	--		--	Water Injection	--
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	0.605	--	--	--	--	--
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.181	--	--	--	CO Catalyst	80.00
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	--	26	--	--	Turbine Design	--
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	--	94	--	--	Proper Combustion	--
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	0.048	--	--	--	--	--
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	--	55.25	--	55 @ 15% O_2	Combustion Control	--
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	--	--	--	50 @ 15% O_2	--	--
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	--	6	25	--	--	--
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW				109 lb/scf fuel	Water Injection	--
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	--	--	--	10 @ 15% O_2	CO Catalyst & Comb. Control	--
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	--	--	--	--	CO Catalyst (No limit indicated)	--
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	--	--	32.4	--	--	--

Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

The lack of demonstrated operation with oil firing suggests rejection of catalytic oxidation as a technically feasible alternative. However, the advent of a second generation catalyst suggests that an oxidation catalyst could be used.

Combustion design is dependent upon the manufacturer's operating specifications, which include the air-to-fuel ratio and the amount of water injected. The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

For the project, the following alternatives were evaluated for natural gas firing as BACT:

1. Oxidation catalyst at 10 ppmvd; maximum annual CO emissions are 78 TPY;
2. Combustion controls; maximum annual CO emissions are 236 TPY.

4.3.2.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $834,700 (Table 4-10), with a cost effectiveness of over $5,280/ton of CO removed. The cost effectiveness is based on natural gas firing at

Table 4-10. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	145,400	Manufacture Estimate - $1,750 per lb/sec mass flow
2. HRSG Modification	138,400	Engineering Estimate
3. Installation	276,900	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	83,100	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	110,700	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	55,400	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	22,100	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	124,800	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	267,100	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	1,223,800	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	143,800	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	823,700	Manufacture Estimate - $1,750 per lb/sec mass flow
B. Contingency	123,500	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	947,200	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	380,900	Capital Recovery of 10% over 20 years
III. ANNUALIZED COST		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,300	4 hours/week, 52 weeks/year, $22/hour and 15% supervisor cost
2. Maintenance	10,900	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	32,200	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
B. ENERGY COSTS		
1. Heat Rate Penalty	69,200	0.2% heat rate penalty. $50/MW energy loss
2. MW Loss Penalty (catalyst changeout)	43,000	Loss of 84.43 MW for one day; cost of natural gas at $3/10^6 Btu deducted from cost
3. Fuel Escalation Costs	31,500	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	21,500	25% of energy costs
C. INDIRECT:		
1. Overhead	9,700	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	21,700	1% of Total and Recurring Capital Cost
3. Insurance	21,700	1% of Total and Recurring Capital Cost
4. Administration	43,400	2% of Total and Recurring Capital Cost
Annualized Capital Costs	143,800	
Annualized Recurring Capital Costs	380,900	
TOTAL ANNUALIZED COSTS	834,700	Sum of Operating and Maintenance and Annualized Capital Costs

Note: All calculations using machine performance were based on 59°F conditions.
Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

10 ppmvd. No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,730,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 120 residential customers over a year. To replace this lost energy, about 1.7 x 10^{10} Btu/yr or about 17 million ft^3/yr of natural gas would be required.

4.3.2.4 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts; and
2. The economic impacts are significant (i.e., an annualized cost of about $34,700 with a cost effectiveness of over $5,280/ton of CO removed).

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not lower CO emissions substantially and will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for combustion turbines have set limits in the 30 ppmvd range. The cost of an oxidation catalyst would be significant and not cost-effective given the proposed emission limit of 30 ppmvd for the CT when firing natural gas.

4.3.3 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CT and are a result of incomplete combustion. The proposed BACT for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions will not exceed 10 ppmvd when firing natural gas. This emission level is similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The proposed VOC emission limits for the CT are in the range approved for other similar sources. The environmental effect of reduced emissions would not be significant.

4.3.4 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emissions level is exceeded for PM/PM10 requiring PSD review (including BACT) for these pollutants. The emission of particulates from the CT is a result of incomplete combustion and trace solids in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on a gas-fueled CT.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions [about 5 pounds per hour (lb/hr)]} is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

Therefore, there are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Natural gas represents BACT for this pollutant.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; in fact, SCR would tend to increase emissions. Thus, natural gas represents BACT because of its inherent low contaminant content.

4.4 BEST AVAILABLE CONTROL TECHNOLOGY - AUXILIARY BOILER

As discussed in Section 2.0, the proposed Orange Cogeneration facility will include a natural gas-fired auxiliary boiler with a maximum heat input capability of 100 mmBtu/hr. The auxiliary boiler will be used to provide supplemental steam to the steam electric turbine and the Orange-Co of Florida, Inc. citrus process facility. Applicable NSPS for the auxiliary are the recently promulgated Subpart Dc which specify emission limiting standards for small industrial-commercial-institutional steam generating units (see Table 4-2). These NSPS do not specify emission limiting standards for natural gas-fired boilers.

The proposed control technologies for the auxiliary boiler are the use of clean fuel for limiting PM and SO_2 emissions, and combustion control for limiting emissions of NO_x, CO and VOCs. The proposed emission rates of PM of 0.01 lb/mmBtu, which reflect the use of natural gas, is equivalent to 0.006 grains per standard cubic feet. This emission level is at or lower than that generally specified for a baghouse.

Pollution preventing combustion controls, i.e, low-NO_x combustors, will limit the formation of NO_x, CO and VOCs in the combustion process. Since the formation of NO_x, and CO and VOC formation are interdependent in the combustion process, a design point that provides the optimum (i.e., minimum) emission level has been proposed. The proposed NO_x emission level of 0.13 lb/mmBtu is lower than the NSPS than that for larger steam generators (0.2 lb/mmBtu for Subpart Db) and lower than that being required as BACT for larger steam electric generators using sophisticated control technology (0.17 lb/mmBtu). Control technology such as flue gas recirculation (FGR) and selective catalytic reduction (SCR) are technically feasible for auxiliary boilers of this size but are generally not cost effective due to limitation of scale. Cost effectiveness will exceed \$5,000/ton and provide limited overall benefits. That is, the reduction of NO_x emissions, that will be at most 20 to 40 tons/year with additional control technology, will be offset by decreased thermal efficiency and additional secondary emissions (e.g., ammonia in the case of SCR).

The proposed CO and VOC emission limits are of the lowest being achieved on an auxiliary boiler in Florida and are based on achieving the NO_x emission limit. The Tropicana Products facility (constructed in 1990) has a slightly higher heat input auxiliary boiler (104 mmBtu/hr) with a CO limit of 0.14 lb/mmBtu and an NO_x emission level of 0.1 lb/mmBtu. The auxiliary boiler for the proposed Orange Cogeneration has a lower overall combined emission of CO and NO_x (i.e., 0.23 lb/mmBtu for CO and NO_x compared to 0.24 lb/mmBtu for the Tropicana facility). Post combustion control, such as an oxidation catalyst, are feasible for CO emissions. These controls have principally been added where the AAQS for CO are being exceeded. Moreover, the cost effectiveness is high with limited overall reduction in emissions (at most 20 to 30 tons/year reduction).

Thus, the proposed BACT emissions levels for NO_x, CO and VOC reflect emissions in range of the lowest being established for auxiliary boilers and utilize pollution prevention technology.

5.0 AIR QUALITY MONITORING DATA

5.1 PSD PRECONSTRUCTION MONITORING

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source is constructed. This analysis may be performed by the use of modeling and/or by monitoring the air quality. Preconstruction monitoring data generally are not required if the ambient air quality concentration before construction is less than the *de minimis* impact monitoring concentrations. Also, if the maximum predicted impact of the source is less than the *de minimis* impact monitoring concentrations, the source generally would be exempt from preconstruction monitoring.

For noncriteria pollutants, EPA recommends that an analysis based on air quality modeling generally should be used instead of monitoring data.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.1, an ambient monitoring analysis is required by PSD regulations for PM(TSP), PM(PM10), NO_2, CO, and O_3 (based on VOC emissions). The maximum concentrations predicted for the proposed project compared to the PSD *de minimis* monitoring concentrations are presented in Table 3-4. Since the maximum predicted impacts from the proposed facility are less than *de minimis* levels for all pollutants, preconstruction monitoring is not required for this project.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

The general modeling approach follows EPA and FDER modeling guidelines. The highest predicted concentrations are compared with both PSD significant impact levels and *de minimis* air quality levels. If a facility exceeds the significant impact level for a particular pollutant, current policies stipulate that the highest annual average and HSH short-term (i.e., 24 hours or less) concentrations be compared with AAQS and PSD increments when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations.

Concentrations for the screening phase were predicted using a coarse receptor grid and a 5-year meteorological record. After a final list of maximum short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the HSH concentration from the screening phase was produced. The air dispersion model then was executed for the entire year during which HSH concentrations were predicted. This approach was used to ensure that valid HSH concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the plant site. Within 50 km of the site, the terrain can be described as simple (i.e., flat to gently rolling). As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex (ISC) dispersion model (EPA, 1992) was selected to evaluate the pollutant emissions from the proposed units and other modeled sources. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes that are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISCST2 short-term model (ISCST2, Version 9227), is an extended version of the single-source (CRSTER) model (EPA, 1977). The ISCST2 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term, and averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code within the ISC model is the ISC long-term (ISCLT2) model. The ISCLT2 model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST2 model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST2 model are presented in Table 6-1. Concentrations caused by stack and volume sources are calculated by the ISCST2 model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST2 model is based on the equation for a continuous and finite crosswind line source. The ISCST2 model has rural and urban options that affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Table 6-1. Major Features of the ISCST2 Model

- Polar or Cartesian coordinate systems for receptor locations
- Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
- Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
- Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
- Direction-specific building heights and projected widths for all sources for which downwash is considered
- Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
- Separation of multiple-point sources
- Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
- Capability of simulating point, line, volume, and area sources
- Capability to calculate dry deposition
- Variation of wind speed with height (wind speed-profile exponent law)
- Concentration estimates for 1-hour to annual average
- Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
- Receptors located above local terrain (i.e., "flagpole" receptors)
- Consideration of time-dependent exponential decay of pollutants
- The method of Pasquill (1976) to account for buoyancy-induced dispersion
- A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
- Procedure for calm-wind processing
- Wind speeds less than 1 m/s are set to 1 m/s

Source: EPA, 1992.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50 percent for every 4 hours of plume travel time).

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility, the rural mode was selected because of the lack of residential, industrial, and commercial development within 3 km of the plant site.

6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST2 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at Tampa International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Tampa, located approximately 65 km to the west-northwest of the site, was selected for use in the study because it is the closest primary weather station to the study area considered to have meteorological data representative of the project site. This station has surrounding topographical features similar to the project site and the most readily available and complete database.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST2 meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Ruskin using the Holzworth approach (Holzworth, 1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

6.3 EMISSION INVENTORY

Stack operating parameters and emission rates for the proposed facility used in the modeling analysis are presented in Table 6-2. Data are presented for the facility operating in both simple cycle and combined cycle modes for various ambient temperatures. For combined cycle mode, data are presented for the CTs operating using water injection or dry low NO_x burners. Data are also presented for the auxiliary boiler, which will be used only during combined cycle operation. Modeling of the proposed facility demonstrated that the facility's PM, SO_2, NO_2, and CO impacts are below the significant impact levels. Therefore, further modeling for these pollutants for comparison to AAQS and PSD Class II increments is not required.

6.4 RECEPTOR LOCATIONS

For comparison to significant impact levels, concentrations were predicted for the following receptor locations:

1. For simple and combined cycle operation, 81 plant boundary and near-field receptors along 36 radials with each radial spaced at 10-degree increments. These receptors are presented in Table 6-3.

Table 6-2. Stack, Operating, and Emission Data Considered in the Air Quality Impact Assessment for the Proposed Facility

Parameter	Simple Cycle Operation			Combined Cycle Units (each)						Auxiliary Boiler
				With Water Injection			With Dry Low NO_x Combustor			
	20°F	40°F	100°F	40°F	59°F	100°F	40°F	59°F	100°F	
Stack Data (ft)										
Height	60	60	60	100	100	100	100	100	100	65
Diameter	9.0	9.0	9.0	8.5	8.5	8.5	8.5	8.5	8.5	3.67
Operating Data										
Temperature (°F)	754	804	859	215	215	215	215	215	215	305
Velocity (ft/sec)	142.9	149.7	119.6	89.6	85.3	68.6	86.6	82.9	67.6	46.9
Pollutant Emission Rates										
PM (lb/hr)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	1.0
NO_2 (TPY)	156.53	165.73	119.47	165.7	159.1	119.5	159.0	152.3	116.3	56.9
CO (lb/hr)	28.5	28.4	21.3	28.4	26.8	21.3	28.3	27.0	21.4	10.0
Sulfuric Acid Mist (lb/hr)	8.19E-02	8.67E-02	6.25E-02	8.67E-02	8.32E-02	6.25E-02	8.24E-02	7.89E-02	6.03E-02	2.31E-02
Polycyclic Organic Matter (lb/hr)	3.95E-04	4.18E-04	3.02E-04	4.18E-04	4.01E-04	3.02E-04	4.18E-04	4.01E-04	3.02E-04	1.11E-04
Formaldehyde (lb/hr)	3.13E-02	3.31E-02	2.39E-02	3.31E-02	3.18E-02	2.39E-02	3.31E-02	3.18E-02	2.39E-02	8.81E-03

Note:
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units. Emission rates presented for the combined cycle operation are for each CT/HRSG unit. The auxiliary boiler will be used during combined cycle operation only.

Table 6-3. Plant Property and Near-Field Receptors Used in the Screening Modeling Analysis

Receptor Location		Receptor Location	
Direction (degrees)	Distance (meters)	Direction (degrees)	Distance (meters)
10	142/200	190	93/100/200
20	149/200	200	97/100/200
30	162/200	210	106/200
40	142/200	220	119/200
50	119/200	230	142/200
60	106/200	240	183/200
70	97/100/200	250	193/200
80	93/100/200	260	184/200
90	91/100/200	270	182/200
100	93/100/200	280	184/200
110	97/100/200	290	193/200
120	106/200	300	210
130	119/200	310	218
140	119/200	320	115/200
150	106/200	330	102/200
160	97/100/200	340	94/100/200
170	93/100/200	350	142/200
180	91/100/200	360	140/200

Note: Direction and distance are relative to the grid origin which is centered between the two proposed HRSG stack locations.

2. For simple cycle operation, 540 general grid receptors located at distances of 200; 400; 700; 1,000; 1,500; 2,000; 2,500; 3,000; 4,000; 5,000, 6,000; 7,000; 8,000; 9,000; and 10,000 m along 36 radials with each radial spaced at 10-degree increments.
3. For combined cycle operation, 432 general grid receptors located at distances of 400; 600; 800; 1,000; 1,500; 2,000; 2,500; 3,000; 3,500; 4,000; 4,500; and 5,000 m along 36 radials with each radial spaced at 10-degree increments.

   These grids were centered between the two proposed CT stack locations.

After the screening modeling was completed, refined modeling was conducted using a receptor grid centered on the receptor that had the highest short-term concentration from the screening analysis. The receptors were located at intervals of 100 m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments, centered on the radial along which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90-degree radial at a distance of 1.0 km, the refined receptor grid would consist of receptors at the following locations:

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	0.8, 0.9, 1.0, 1.1, 1.2, 1.3, and 1.4 per direction

To ensure that a valid maximum concentration was calculated, concentrations were predicted using the refined grid for the entire year that produced the highest concentration from the screening receptor grid.

Refined modeling analysis was not performed for the annual averaging period because the spatial distribution of annual average concentrations are not expected to vary significantly from those produced from the screening analysis.

The maximum PSD increment consumption at the Chassahowitzka Wilderness Area was determined for the proposed facility alone at 13 discrete receptors located along the boundary of the Class I area. The highest predicted concentrations for the proposed facility for the 5 years of meteorological data were compared with the recommended NPS Class I significance values for PM and NO_2 (see Section 3.2.6).

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stacks for the proposed units (i.e., CT stack for simple cycle operation, HRSG stack, and auxiliary boiler stack) will comply with the GEP stack height regulations. However, these stacks will be less than GEP. Therefore, the potential for building downwash to occur was considered in the modeling analysis for these stacks.

The ISC model uses two procedures to address the effects of building downwash. For both methods the direction-specific building dimensions are input for H_b and l_b for 36 radial directions, with each direction representing a 10-degree sector, which uses these parameters to modify the dispersion parameters. The H_b is the building height and l_b is the lesser of the building height or projected width. For short stacks (i.e., physical stack height is less than $H_b + 0.5\ l_b$), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than $H_b + 0.5\ l_b$ but less than GEP, the Huber-Snyder (1976) method is used.

The building dimensions considered in the modeling analysis are presented in Table 6-4. A detailed listing of direction-specific building data used in the modeling analysis is given in Appendix B.

Table 6-4. Building Dimensions Used to Address Potential Building Wake Effects

Source	Stack Height		Building(s)	Actual Buidling Dimensions (m)			Maximum Projected Width[a]
Unit/Stack	ft	m	of Influence	Length	Width	Height	(m)
Turbine Stack (CT--Simple Cycle)	60	18.3	HRSG Building	19.8	10.4	17.1	22.4
			CT Hood/Intake Structure	8.8	16.5	11.0	18.7
HRSG Stack (CT--Combined Cycle)	100	30.5	HRSG Building	19.8	10.4	17.1	22.4
Auxiliary Boiler	65	19.8	Plant Services Building	31.7	24.4	8.8	40.0
			Control Building	12.2	9.1	9.1	15.2
CT Hood/Intake Structure			8.8	16.5	11.0	18.7	

Note: Refer to Appendix C for BREEZEWAKE output depicting direction-specific building data used in the modeling analysis.

[a] Diagonal of actual building dimensions.

7.0 AIR QUALITY MODELING RESULTS

7.1 SIGNIFICANT IMPACT ANALYSIS FOR PROPOSED FACILITY

A summary of the maximum concentrations as a result of the proposed facility operating at simple and combined cycle modes at various design temperatures and with two control technologies (i.e., water injection and dry low NO_x technology) is presented in Table 7-1. The results are presented for all regulated pollutants considered in the modeling analysis. The modeling was performed based on the operating conditions for the ambient temperature that produced the highest emissions or lowest flow rate. This approach ensured that the maximum impacts from the proposed facility were obtained.

The overall maximum impacts from the screening analysis for all scenarios considered in the modeling analysis are presented in Table 7-2. Based on these results, a refined analysis was performed.

A summary of the refined impacts developed from the overall maximum concentrations produced in the screening analysis is presented in Table 7-3 and compared to the significant impact levels and *de minimis* monitoring levels.

The maximum predicted 24-hour and annual average PM(TSP) concentrations due to the proposed facility are 3.47 and 0.10 $\mu g/m^3$, respectively. Maximum PM10 impacts are assumed to be identical to the PM(TSP) impacts. Since these maximum concentrations are below the significance and *de minimis* levels for these pollutants, no further modeling analysis is necessary.

The maximum predicted annual NO_2 concentration due to the proposed facility is 0.90 $\mu g/m^3$. Because this level of impact is below the significance and *de minimis* levels, no further modeling analysis was performed.

The maximum predicted 1- and 8-hour average CO concentrations due to the proposed facility are 71.3 and 34.8 $\mu g/m^3$, respectively. These maximum impacts are less than the CO significance impact levels. Because the

Table 7-1. Summary of Screening Modeling Impacts for the Orange Cogeneration Facility

Pollutant	Averaging Period	Ambient Temp (°F)	Simple Cycle Operation	Maximum Impacts ($\mu g/m^3$) Combined Cycle Units Only: Water Inj	Combined Cycle Units Only: DLN	Combined Cycle Units with Aux Boiler: Water Inj	Combined Cycle Units with Aux Boiler: DLN
PM(PM10)	Annual	20	0.0059	NM	NM	NM	NM
		40	0.0055	0.055	0.056	0.083	0.084
		59	NM	0.057	0.058	0.085	0.087
		100	0.0130	0.071	0.071	0.10	0.10
	24-Hour	20	1.47	NM	NM	NM	NM
		40	1.14	2.44	2.48	2.57	2.61
		59	NM	2.50	2.54	2.63	2.67
		100	3.41	3.31	3.35	3.43	3.47
NO_2	Annual	20	0.042	NM	NM	NM	NM
		40	0.041	0.41	0.41	0.87	0.88
		59	NM	0.41	0.41	0.88	0.89
		100	0.069	0.39	0.38	0.90	0.90
CO	1-Hour	20	66.51	NM	NM	NM	NM
		40	59.12	44.8	45.9	58.4	58.8
		59	NM	44.0	45.3	57.8	58.3
		100	70.37	41.1	41.8	55.7	56.0
	8-Hour	20	18.53	NM	NM	NM	NM
		40	14.81	24.7	25.1	26.9	29.4
		59	NM	24.0	24.5	28.6	29.1
		100	27.35	21.9	22.3	27.7	28.0

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units.
Refer to Appendix B for location and time period of maximum concentrations.

DLN = dry low NO_x
NM = not modeled
Water Inj = water injection

Table 7-2. Summary of Overall Maximum Screening Modeling Impacts for the Orange Cogeneration Facility

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Operating Condition
PM(PM10)	Annual	0.10	Combined cycle; DLN; 100°F
	24-Hour	3.47	Combined cycle; DLN; 100°F
NO_2	Annual	0.90	Combined cycle; DLN; 100°F
CO	1-Hour	70.4	Simple cycle; 100°F
	8-Hour	29.4	Combined cycle; DLN; 40°F

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units.
Refer to Appendix B for location and time period of maximum concentrations.

DLN = dry low NO_x

Table 7-3. Summary of Maximum Refined Modeling Impacts for the Orange Cogeneration Facility

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Significant Impact Levels ($\mu g/m^3$)	*de minimus* Monitoring Level ($\mu g/m^3$)
PM(PM10)	Annual	0.10[a]	1	NA
	24-Hour	3.47[a]	5	10
NO_2	Annual	0.90[a]	1	14
CO	1-Hour	71.3[b]	2,000	NA
	8-Hour	34.8[c]	500	575

Note: Highest refined concentrations reported for all averaging periods.

NA = not applicable.

[a] Combined cycle operation with DLN combustors at ambient temperature of 100°F.
[b] Simple cycle operation at ambient temperature of 100°F.
[c] Combined cycle operation with DLN combustors at ambient temperature of 40°F.

maximum predicted impacts due to the proposed facility are less than the CO significance and *de minimis* levels, additional modeling is not required for this pollutant.

No significance levels have been established for sulfuric acid mist. There is also no ambient measurement method established for this pollutant and, thus, no *de minimis* monitoring concentration. Therefore, no further PSD modeling analysis was conducted. Sulfuric acid mist, along with formaldehyde and polycyclic organic matter were addressed as toxic air pollutants for comparison to the Florida NTLs (refer to Section 7.1.3).

7.2 PSD CLASS I SIGNIFICANCE ANALYSIS

Maximum NO_2 and PM concentrations predicted at the PSD Class I area of the Chassahowitzka National Wilderness Area for comparison to NPS's recommended PSD Class I significance levels are presented in Table 7-4. Results are presented for simple and combined cycle operation. For combined cycle operation, results are presented for the CTs operating with water injection and dry low NO_x combustors. Impacts for 40°F and 100°F are presented, representing the maximum emission—maximum flow and minimum emission—minimum flow cases. The overall maximum concentrations predicted for all modeled scenarios, which are compared to the NPS—recommended Class I significance levels, are presented in Table 7-5.

The maximum predicted PM 24-hour and annual concentrations in the Class I area are 0.030 and 0.0017 $\mu g/m^3$, respectively. These predicted impacts are below the NPS Class I 24-hour and annual significance levels of 0.33 and 0.1 $\mu g/m^3$, respectively.

The maximum predicted NO_2 annual concentration in the Class I area is 0.013 $\mu g/m^3$. This predicted impact is below the NPS Class I annual significance level of 0.025 $\mu g/m^3$.

As the results indicate, the proposed facility's impacts are below the NPS-recommended Class I significance values for all averaging periods and

Table 7-4. Summary of Maximum Predicted PM and NO_2 Concentrations Due to the Proposed Facility at the Class I Area of the Chassahowitzka National Wilderness Area

Pollutant	Averaging Period	Ambient Temp (°F)	Simple Cycle Operation	Maximum Impacts (µg/m³) Combined Cycle Units Only: Water Inj	Combined Cycle Units Only: DLN	Combined Cycle Units with Aux Boiler: Water Inj	Combined Cycle Units with Aux Boiler: DLN
PM(PM10)	Annual	40	0.00054	0.0014	0.0014	0.0016	0.0016
		100	0.00060	0.0014	0.0014	0.0017	0.0017
	24-Hour	40	0.010	0.024	0.024	0.028	0.028
		100	0.011	0.025	0.025	0.030	0.030
NO_2	Annual	40	0.0041	0.011	0.010	0.013	0.013
		100	0.0033	0.0079	0.0077	0.011	0.010

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units.
Refer to Appendix B for location and time period of maximum concentrations.

DLN = dry low NO_x
Water Inj = water injection

Table 7-5. Summary of Overall Maximum Predicted PM and NO_2 Concentrations Due to the Proposed Facility at the Class I Area of the Chassahowitzka National Wilderness Area

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	NPS-Recommended Class I Significance Levels ($\mu g/m^3$)	Operating Condition
PM(PM10)	Annual	0.0017	0.1	Combined Cycle; 100°F
	24-Hour	0.030	0.33	Combined Cycle; 100°F
NO_2	Annual	0.013	0.025	Combined Cycle; 40°F

Note: Highest concentrations reported for all averaging periods.
Simple cycle operation includes one CT unit. Combined cycle operation includes two CT/HRSG units and auxiliary boiler.

modeled pollutants. Therefore, no further Class I modeling analysis was conducted.

7.3 TOXIC POLLUTANT IMPACT ANALYSIS

The maximum impacts of regulated and nonregulated toxic air pollutants that will be emitted by the proposed facility are presented in Table 7-6. These impacts represent the highest impacts predicted from the screening analysis for the combined cycle operation with dry low-NO_x combustors. This design case was modeled since the highest concentrations were predicted for the criteria pollutants from among the operating design cases considered for the project.

The maximum 8-hour, 24-hour, and annual concentrations are compared to the Florida NTLs. As shown, the predicted impacts are below the NTLs for all pollutants and averaging times. Therefore, the emissions from the proposed facility are not expected to pose a significant health risk to the public.

7.4 ADDITIONAL IMPACT ANALYSIS

7.4.1 IMPACTS UPON VEGETATION

The response of vegetation to atmospheric pollutants is influenced by the concentration of the pollutant, duration of the exposure and the frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term higher doses. A dose is the product of the concentration of the pollutant and the duration of the exposure. The impact of the proposed facility on regional vegetation was assessed by comparing pollutant doses that are predicted from modeling with threshold doses reported from the scientific literature which could adversely affect plant species typical of those present in the region.

Predicted impacts of all regulated pollutants considered in the analysis are less than the significant impact levels (see Table 7-3). As a result,

Table 7-6. Summary of Maximum Concentrations Due to the Proposed Facility for the Air Toxic Modeling Analysis

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Florida No Threat Levels ($\mu g/m^3$)
Formaldehyde	8-hour	0.031[a]	4.5
	24-hour	0.018[a]	1.08
	Annual	0.00067[b]	0.077
Polycyclic Organic Matter	8-hour	0.00040[a]	NE
	24-hour	0.00022[b]	NE
	Annual	0.00001[b]	NE
Sulfuric Acid Mist	8-hour	0.076[a]	10
	24-hour	0.043[b]	2.38
	Annual	0.0017[b]	NE

Note: Highest concentrations reported for all averaging periods.
NE = none established.

[a] Combined cycle operation with DLN combustors at ambient temperature of 40°F.

[b] Combined cycle operation with DLN combustors at ambient temperature of 100°F.

no impacts are expected to occur to vegetation as a result of the proposed emissions of other regulated pollutants.

7.4.2 IMPACTS TO SOILS

Because the predicted impacts for all pollutants considered in the analysis are less than the significant impact levels, the facility is not expected to have a significant adverse impact on regional vegetation or soils.

7.4.3 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of personnel will be used to operate the proposed facility. These personnel are not expected to have a significant effect on the residential, commercial, and industrial growth in Polk County.

7.4.4 IMPACTS TO VISIBILITY

The Orange Cogeneration Facility is located approximately 114 km from the Chassahowitzka Wilderness Area, a PSD Class I area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were calculated for particulates and nitrogen oxides (as nitrogen dioxide). Worst-case NO_x and PM emissions at the 40-degree design temperature for combined cycle operation with water injection were used in order to maximize impacts at the Class I area. The results of the screening analysis are presented in Table 7-7. Based on these results the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-7. Visibility Analysis for the Orange Cogeneration Facility on the PSD Class I Area

Visual Effects Screening Analysis for
Source: ORANGE COGENERATION FACILITY
Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	11.0	lb/hr
NOx (as NO2)	88.70	lb/hr
Primary NO2	.00	lb/hr
Soot	.00	lb/hr
Primary SO4	.20	lb/hr

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	114.00 km
Min. Source-Class I Distance:	114.00 km
Max. Source-Class I Distance:	134.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	114.0	84.	2.00	.008	.05	.000
SKY	140.	84.	114.0	84.	2.00	.002	.05	-.000
TERRAIN	10.	84.	114.0	84.	2.00	.000	.05	.000
TERRAIN	140.	84.	114.0	84.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	110.4	94.	2.00	.009	.05	.000
SKY	140.	75.	110.4	94.	2.00	.002	.05	-.000
TERRAIN	10.	60.	104.3	109.	2.00	.001	.05	.000
TERRAIN	140.	60.	104.3	109.	2.00	.000	.05	.000

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APPENDIX A

DESIGN INFORMATION, STACK PARAMETERS, AND EXAMPLE CALCULATIONS FOR THE PROPOSED ORANGE COGENERATION FACILITY

ORANGE COGENERATION FACILITY

EXAMPLE CALCULATIONS FOR DRY LOW NO_x COMBUSTOR, COMBINED CYCLE OPERATION, AT AMBIENT TEMPERATURE OF 59°F

(Procedures used in the calculations for other combustion turbine operations are identical to these example calculations.)

<u>Table A-9</u>: (Note: all other data not calculated but supplied by Manufacturer)

Heat Input (10^6 Btu/hr):

Power (kW) x Heat Rate (10^6 Btu/kWh)

$38{,}638 \times 8{,}829/10^6 = 341.13 \times 10^6$ Btu/hr

Natural Gas Consumption (cf/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/cf) (lower heating value)

$341.13 \times 10^6 \div 946 = 360{,}608$ cf/hr

Volume Flow (acfm) - See Note A:

$V = mRT/PM$

980,775 lb/hr x 1,545 ft-lb/°R x (873°F + 460°F)

÷ (28.52 x 2,116.8 lb/ft^2) ÷ 60 min/hr

= 557,641 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

980,775 lb/hr x 1,545 ft-lb/°R x (68°F + 460°F)

÷ (28.52 x 2,116.8 lb/ft^2) ÷ 60 min/hr

= 220,881 scfm

Volume Flow (acfm) from HRSG:

CT exhaust adjusted for HRSG exhaust temperature

557,641 acfm x (215°F + 460°F) ÷ (873°F + 460°F)

= 282,376 acfm

HRSG Exhaust Velocity (ft/sec):

Volume Flow (acfm) ÷ Area (ft^2) ÷ 60 sec/min

282,376 acfm ÷ 60 ÷ (8.5^2 ÷ 4 x 3.14159)

= 82.9 ft/sec

Table A-10:

PM/PM10 Emissions:

5 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton

= 21.9 ton/yr

SO_2 Emissions:

360,608 cf/hr x 1 gr/100 cf ÷ 7,000 gr/lb x 2 lb SO_2/lb S

= 1.03 lb/hr

= 4.51 ton/year

NO_x Emissions - See Note B:

25 ppm x [20.9 x (1 - 6.58/100) - 14.34] ÷ 5.9 x 2,116.8 lb/ft^2

x 557,641 ft^3/min x 46 (molecular wgt NO_2) x 60 min/hr

÷ [1,545 ft-lb/°F x (873°F + 460°F) x 10^6 (adjust for ppm)]

= 34.8 lb/hr

= 152.3 ton/year

CO Emissions - See Note C:

30 ppm x (1 - 6.58/100) x 557,641 acfm x 2,116.8 lb/ft^2

x 28 (molecular wgt. of carbon) x 60 min/hr ÷ [1,545 ft-lb/°F

x (873 + 460°F) x 10^6]

= 27.0 lb/hr

= 118.2 ton/year

VOC Emissions - See Note C:

10 ppm x (1 - 6.58/100) x 557,641 acfm x 2,116.8 lb/ft^2

x 12 (molecular wgt. of carbon) x 60 min/hr ÷ [1,545 ft-lb/°F

x (873°F + 460°F) x 10^6]

= 3.86 lb/hr

= 16.9 ton/year

Lead Emissions:

Negligible

Table A-11:

H_2SO_4 Mist Emissions:

Based on 5 percent of SO_2 converted to sulfuric acid mist

1.03 lb/hr x 1.53 lb H_2SO_4/lb SO_2 x 0.05 (converted)

= 0.0789 lb/hr

= 0.346 ton/year

Arsenic, Beryllium, Mercury, Fluoride Emissions:

Negligible

Table A-12:

Polycyclic Organic Matter Emissions:

Emission factor (pg/J) x 2.324 $\frac{\text{lb}/10^{12}\text{ Btu}}{\text{pg/J}}$ x Heat input rate (10^{12} Btu/hr)

0.48 pg/J x 2.324 x 341.13 x 10^{-6} (10^{12} Btu/hr)

= 0.00040 lb/hr

= 0.00176 ton/year

Formaldehyde Emissions:

Emission factor (pg/J) x 2.324 $\frac{\text{lb}/10^{12}\text{ Btu}}{\text{pg/J}}$ x Heat input rate (10^{12} Btu/hr)

38 pg/J x 2.324 x 341.13 x 10^{-6} (10^{12} Btu/hr)

= 0.0318 lb/hr

= 0.139 ton/year

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT \div M$$

where:
- P = pressure = 2116.8 lb/ft^2
- m = mass flow of gas (lb/hr)
- R = universal gas constant = 1,545 ft-lb/°R
- M = molecular weight of gas
- T = temperature (°R)

NOTE B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

(From 40 CFR Part 60; Appendix A, Method 20, Equation 20-4)

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry}) \div 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act} \div (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

(From Method 20; Equation 20-1)

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O);\ \text{(From Method 20; Equation 20-1)}$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O) \div 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act} \div (1 - \%H_2O))]\ (1 - \%H_2O) \div 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2] \div 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx} \div (RT * 5.9)$$

NOTE C

Same as Note B except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$\begin{aligned} m_{CO} &= PV_{CO\ Act}M_{CO} \div RT \\ &= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO} \div RT \end{aligned}$$

Table A-1. Design Information and Stack Parameters for the Proposed Orange Cogen Facility, Simple Cycle Operation GE LM6000-PA, Natural Gas, Water Injection

Data	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
General	16081	16082	16084	16085	16086
Power (kW)	39,571.0	41,505.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,111.0	9,325.0	9,753.0
CT Exhaust Flow					
Mass Flow (lb/hr)	1,046,409	1,049,860	996,693	896,512	797,377
Temperature (oF)	754	804	830	842	859
Moisture (% Vol.)	8.17	9.11	9.65	10.01	10.99
Oxygen (% Vol.)	14.23	13.77	13.61	13.72	13.68
Molecular Weight	28.33	28.24	28.19	28.14	28.02
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu					
Power (kW)	39,571.0	41,505.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,111.0	9,325.0	9,753.0
Heat Input (MMBtu/hr)	354.32	374.87	359.82	313.30	270.30
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)					
(cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)					
Heat Input (MMBtu/hr)	354.32	374.87	359.82	313.30	270.30
Heat Content, LHV (Btu/lb)	19,000	19,000	19,000	19,000	19,000
Natural Gas (lb/hr)	18,648.4	19,730.2	18,937.9	16,489.5	14,226.5
Heat Content, LHV (Btu/cf)	946	946	946	946	946
Natural Gas (cf/hr)	374,544	396,272	380,360	331,185	285,734
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	1,046,409	1,049,860	996,693	896,512	797,377
Temperature (°F)	754	804	830	842	859
Molecular Weight	28.33	28.24	28.19	28.14	28.02
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	1,046,409	1,049,860	996,693	896,512	797,377
Temperature (°F)	68	68	68	68	68
Molecular Weight	28.33	28.24	28.19	28.14	28.02
Volume Flow (scfm)	237,210	238,749	227,114	204,637	182,766
CT Stack Data					
Stack Height (ft)	60	60	60	60	60
Diameter (ft)	9.0	9.0	9.0	9.0	9.0
Volume Flow (acfm) from CT= [Volume flow (acfm) x (CT temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]					
Volume Flow (acfm) from CT	545,404	571,551	554,881	504,616	456,568
CT Temperature (°F)	754	804	830	842	859
CT Temperature (°F)	754	804	830	842	859
Volume Flow (acfm) from CT	545,404	571,551	554,881	504,616	456,568
Velocity (ft/sec)= Volume flow (acfm) from CT ÷ [((diameter)^2÷ 4) x 3.14159] ÷ 60 sec/min					
Volume Flow (acfm) from CT	545,404	571,551	554,881	504,616	456,568
Diameter (ft)	9.0	9.0	9.0	9.0	9.0
Velocity (ft/sec)	142.9	149.7	145.4	132.2	119.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft^2

Source: Stewart & Stevenson, 1993. (4/13/93)

Table A-2. Maximum Criteria Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer					
PM, lb/hr (manufacturer)	5.0	5.0	5.0	5.0	5.0
TPY	21.90	21.90	21.90	21.90	21.90
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100					
Natural Gas (cf/hr)	374,544	396,272	380,360	331,185	285,734
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)	2.0	2.0	2.0	2.0	2.0
SO2, lb/hr	1.07	1.13	1.09	0.95	0.82
TPY	4.69	4.96	4.76	4.14	3.58
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]					
Basis, ppm^a	25.0	25.0	25.0	25.0	25.0
Moisture (%)	8.17	9.11	9.6543	10.0102	10.9915
Oxygen (%)	14.23	13.77	13.6119	13.7157	13.6848
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Temperature (°F)	754	804	830	842	859
NOx, lb/hr	35.7	37.8	36.3	31.6	27.3
TPY	156.53	165.73	159.10	138.51	119.47
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]					
Basis, ppm^b	30.0	30.0	30.0	30.0	30.0
Moisture (%)	8.1654	9.1117	9.6543	10.0102	10.9915
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Temperature (°F)	754	804	830	842	859
lb/hr	28.5	28.4	26.8	24.1	21.3
TPY	124.78	124.30	117.54	105.49	93.19
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as carbon) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]					
Basis, ppm^b	10.0	10.0	10.0	10.0	10.0
Moisture (%)	8.1654	9.1117	9.6543	10.0102	10.9915
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Temperature (°F)	754	804	830	842	859
lb/hr	4.07	4.05	3.83	3.44	3.04
TPY	17.8	17.8	16.8	15.1	13.3
Lead (lb/hr)= Negligible					
Basis, lb/10E+12 Btu	NA	NA	NA	NA	NA
HIR (MMBtu/hr)	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

^a corrected to 15% O2 and dry conditions
^b corrected to dry conditions

Table A-3. Other Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Arsenic (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	0.027	0.027	0.027	0.027	0.027
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	9.57E-06	1.01E-05	9.72E-06	8.46E-06	7.30E-06
	TPY	4.19E-05	4.43E-05	4.26E-05	3.71E-05	3.20E-05
Fluoride (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)	1.1	1.1	1.1	0.9	0.8
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	8.19E-02	8.67E-02	8.32E-02	7.24E-02	6.25E-02
	TPY	3.59E-01	3.80E-01	3.64E-01	3.17E-01	2.74E-01

Source: (1) DER, 1992

Table A-4. Non-Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Manganese (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	3.94E-04	4.17E-04	4.00E-04	3.49E-04	3.01E-04
	TPY	1.73E-03	1.83E-03	1.75E-03	1.53E-03	1.32E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	3.12E-02	3.30E-02	3.17E-02	2.76E-02	2.38E-02
	TPY	1.37E-01	1.45E-01	1.39E-01	1.21E-01	1.04E-01

Source: (1) EPA, 1990

Table A-5. Design Information and Stack Parameters for the Proposed Orange Cogen Facility, Combined Cycle Operation GE LM6000-PA, Natural Gas, Water Injection

Data	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
General	16081	16082	16084	16085	16086
Power (kW)	39,571.0	41,505.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,111.0	9,325.0	9,753.0
CT Exhaust Flow					
Mass Flow (lb/hr)	1,046,409	1,049,860	996,693	896,512	797,377
Temperature (oF)	754	804	830	842	859
Moisture (% Vol.)	8.17	9.11	9.65	10.01	10.99
Oxygen (% Vol.)	14.23	13.77	13.61	13.72	13.68
Molecular Weight	28.33	28.24	28.19	28.14	28.02
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu					
Power (kW)	39,571.0	41,505.0	39,493.0	33,598.0	27,715.0
Heat Rate (Btu/kwh)	8,954.0	9,032.0	9,111.0	9,325.0	9,753.0
Heat Input (MMBtu/hr)	354.32	374.87	359.82	313.30	270.30
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb) (cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)					
Heat Input (MMBtu/hr)	354.32	374.87	359.82	313.30	270.30
Heat Content, LHV (Btu/lb)	19,000	19,000	19,000	19,000	19,000
Natural Gas (lb/hr)	18,648.4	19,730.2	18,937.9	16,489.5	14,226.5
Heat Content, LHV (Btu/cf)	946	946	946	946	946
Natural Gas (cf/hr)	374,544	396,272	380,360	331,185	285,734
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	1,046,409	1,049,860	996,693	896,512	797,377
Temperature (°F)	754	804	830	842	859
Molecular Weight	28.33	28.24	28.19	28.14	28.02
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	1,046,409	1,049,860	996,693	896,512	797,377
Temperature (°F)	68	68	68	68	68
Molecular Weight	28.33	28.24	28.19	28.14	28.02
Volume Flow (scfm)	237,210	238,749	227,114	204,637	182,766
HRSG Stack Data					
Stack Height (ft)	100	100	100	100	100
Diameter (ft)	8.5	8.5	8.5	8.5	8.5
Volume Flow (acfm) from HRSG= [Volume flow (acfm) from CT x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]					
Volume Flow (acfm) from CT	545,404	571,551	554,881	504,616	456,568
CT Temperature (°F)	754	804	830	842	859
HRSG Temperature (°F)	215	215	215	215	215
Volume Flow (acfm) from HRSG	303,252	305,219	290,345	261,610	233,649
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min					
Volume Flow (acfm) from HRSG	303,252	305,219	290,345	261,610	233,649
Diameter (ft)	8.5	8.5	8.5	8.5	8.5
Velocity (ft/sec)	89.1	89.6	85.3	76.8	68.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

Source: Stewart & Stevenson, 1993. (4/13/93)

Table A-6. Maximum Criteria Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer					
PM, lb/hr (manufacturer)	5.0	5.0	5.0	5.0	5.0
TPY	21.90	21.90	21.90	21.90	21.90
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100					
Natural Gas (cf/hr)	374,544	396,272	380,360	331,185	285,734
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)	2.0	2.0	2.0	2.0	2.0
SO2, lb/hr	1.07	1.13	1.09	0.95	0.82
TPY	4.69	4.96	4.76	4.14	3.58
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]					
Basis, ppm^a	25.0	25.0	25.0	25.0	25.0
Moisture (%)	8.17	9.11	9.65	10.01	10.99
Oxygen (%)	14.23	13.77	13.61	13.72	13.68
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Temperature (°F)	754	804	830	842	859
lb/hr	35.7	37.8	36.3	31.6	27.3
TPY	156.53	165.73	159.10	138.51	119.47
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]					
Basis, ppm^b	30.0	30.0	30.0	30.0	30.0
Moisture (%)	8.17	9.11	9.65	10.01	10.99
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Temperature (°F)	754	804	830	842	859
lb/hr	28.5	28.4	26.8	24.1	21.3
TPY	124.78	124.30	117.54	105.49	93.19
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as carbon) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]					
Basis, ppm^b	10.0	10.0	10.0	10.0	10.0
Moisture (%)	8.17	9.11	9.65	10.01	10.99
Volume Flow (acfm)	545,404	571,551	554,881	504,616	456,568
Temperature (°F)	754	804	830	842	859
lb/hr	4.07	4.05	3.83	3.44	3.04
TPY	17.8	17.8	16.8	15.1	13.3
Lead (lb/hr)= Negligible					
Basis, lb/10E+12 Btu	NA	NA	NA	NA	NA
HIR (MMBtu/hr)	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

^a corrected to 15% O2 and dry conditions
^b corrected to dry conditions

Table A-7. Other Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Arsenic (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	0.027	0.027	0.027	0.027	0.027
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	9.57E-06	1.01E-05	9.72E-06	8.46E-06	7.30E-06
	TPY	4.19E-05	4.43E-05	4.26E-05	3.71E-05	3.20E-05
Fluoride (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)	1.1	1.1	1.1	0.9	0.8
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	8.19E-02	8.67E-02	8.32E-02	7.24E-02	6.25E-02
	TPY	3.59E-01	3.80E-01	3.64E-01	3.17E-01	2.74E-01

Source: (1) DER, 1992

Table A-8. Non-Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Manganese (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	3.94E-04	4.17E-04	4.00E-04	3.49E-04	3.01E-04
	TPY	1.73E-03	1.83E-03	1.75E-03	1.53E-03	1.32E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	3.12E-02	3.30E-02	3.17E-02	2.76E-02	2.38E-02
	TPY	1.37E-01	1.45E-01	1.39E-01	1.21E-01	1.04E-01

Source: (1) EPA, 1990

Table A-9. Design Information and Stack Parameters for the Proposed Orange Cogen Facility, Combined Cycle Operation GE LM6000-PA, Natural Gas, Dry Low NOx

Data	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
General	11011	11012	11014	11015	11016
Power (kW)	39,122.0	40,793.0	38,638.0	33,240.0	27,344.0
Heat Rate (Btu/kwh)	8,699.0	8,731.0	8,829.0	9,058.0	9,532.0
CT Exhaust Flow					
Mass Flow (lb/hr)	1,031,596	1,026,032	980,775	887,935	791,613
Temperature (oF)	796	852	873	881	887
Moisture (% Vol.)	5.54	6.08	6.58	7.45	9.02
Oxygen (% Vol.)	14.81	14.44	14.34	14.30	14.15
Molecular Weight	28.62	28.57	28.52	28.42	28.23
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu					
Power (kW)	39,122.0	40,793.0	38,638.0	33,240.0	27,344.0
Heat Rate (Btu/kwh)	8,699.0	8,731.0	8,829.0	9,058.0	9,532.0
Heat Input (MMBtu/hr)	340.32	356.16	341.13	301.09	260.64
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb) (cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)					
Heat Input (MMBtu/hr)	340.32	356.16	341.13	301.09	260.64
Heat Content, LHV (Btu/lb)	19,000	19,000	19,000	19,000	19,000
Natural Gas (lb/hr)	17,911.7	18,745.5	17,954.5	15,846.7	13,718.1
Heat Content, LHV (Btu/cf)	946	946	946	946	946
Natural Gas (cf/hr)	359,749	376,494	360,608	318,275	275,521
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	1,031,596	1,026,032	980,775	887,935	791,613
Temperature (°F)	796	852	873	881	887
Molecular Weight	28.62	28.57	28.52	28.42	28.23
Volume Flow (acfm)	550,717	573,084	557,641	509,736	459,410
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	1,031,596	1,026,032	980,775	887,935	791,613
Temperature (°F)	68	68	68	68	68
Molecular Weight	28.62	28.57	28.52	28.42	28.23
Volume Flow (scfm)	231,512	230,632	220,881	200,702	180,081
HRSG Stack Data					
Stack Height (ft)	100	100	100	100	100
Diameter (ft)	8.5	8.5	8.5	8.5	8.5
Volume Flow (acfm) from HRSG= [Volume flow (acfm) from CT x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]					
Volume Flow (acfm) from CT	550,717	573,084	557,641	509,736	459,410
CT Temperature (°F)	796	852	873	881	887
HRSG Temperature (°F)	215	215	215	215	215
Volume Flow (acfm) from HRSG	295,966	294,841	282,376	256,579	230,217
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)² ÷ 4) x 3.14159] ÷ 60 sec/min					
Volume Flow (acfm) from HRSG	295,966	294,841	282,376	256,579	230,217
Diameter (ft)	8.5	8.5	8.5	8.5	8.5
Velocity (ft/sec)	86.9	86.6	82.9	75.4	67.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

Source: Stewart & Stevenson, 1993. (4/13/93)

Table A-10. Maximum Criteria Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer					
PM, lb/hr (manufacturer)	5.0	5.0	5.0	5.0	5.0
TPY	21.90	21.90	21.90	21.90	21.90
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100					
Natural Gas (cf/hr)	359,749	376,494	360,608	318,275	275,521
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)	2.0	2.0	2.0	2.0	2.0
SO2, lb/hr	1.03	1.08	1.03	0.91	0.79
TPY	4.50	4.71	4.51	3.98	3.45
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]					
Basis, ppm^a	25.0	25.0	25.0	25.0	25.0
Moisture (%)	5.54	6.08	6.58	7.45	9.02
Oxygen (%)	14.81	14.44	14.34	14.30	14.15
Volume Flow (acfm)	550,717	573,084	557,641	509,736	459,410
Temperature (°F)	796	852	873	881	887
lb/hr	34.7	36.3	34.8	30.7	26.6
TPY	151.88	159.03	152.32	134.42	116.34
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]					
Basis, ppm^b	30.0	30.0	30.0	30.0	30.0
Moisture (%)	5.54	6.08	6.58	7.45	9.02
Volume Flow (acfm)	550,717	573,084	557,641	509,736	459,410
Temperature (°F)	796	852	873	881	887
lb/hr	28.6	28.3	27.0	24.3	21.4
TPY	125.27	124.08	118.21	106.40	93.85
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as carbon) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]					
Basis, ppm^b	10.0	10.0	10.0	10.0	10.0
Moisture (%)	5.54	6.08	6.58	7.45	9.02
Volume Flow (acfm)	550,717	573,084	557,641	509,736	459,410
Temperature (°F)	796	852	873	881	887
lb/hr	4.09	4.05	3.86	3.47	3.06
TPY	17.9	17.7	16.9	15.2	13.4
Lead (lb/hr)= Negligible					
Basis, lb/10E+12 Btu	NA	NA	NA	NA	NA
HIR (MMBtu/hr)	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

^a corrected to 15% O2 dry conditions
^b corrected to dry conditions

Table A-11. Other Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Arsenic (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	0.027	0.027	0.027	0.027	0.027
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	9.57E-06	1.01E-05	9.72E-06	8.46E-06	7.30E-06
	TPY	4.19E-05	4.43E-05	4.26E-05	3.71E-05	3.20E-05
Fluoride (lb/hr)= Negligible						
	lb/10E+12 Btu	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)	1.0	1.1	1.0	0.9	0.8
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	7.87E-02	8.24E-02	7.89E-02	6.96E-02	6.03E-02
	TPY	3.45E-01	3.61E-01	3.46E-01	3.05E-01	2.64E-01

Source: (1) DER, 1992

Table A-12. Non-Regulated Pollutant Emissions for the Proposed Orange Cogeneration Facility
GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Units	Gas Turbine Natural Gas 20 °F	Gas Turbine Natural Gas 40 °F	Gas Turbine Natural Gas 59 °F	Gas Turbine Natural Gas 80 °F	Gas Turbine Natural Gas 100 °F
Manganese (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	3.94E-04	4.17E-04	4.00E-04	3.49E-04	3.01E-04
	TPY	1.73E-03	1.83E-03	1.75E-03	1.53E-03	1.32E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	HIR (MMBtu/hr)	354.3	374.9	359.8	313.3	270.3
	lb/hr	3.12E-02	3.30E-02	3.17E-02	2.76E-02	2.38E-02
	TPY	1.37E-01	1.45E-01	1.39E-01	1.21E-01	1.04E-01

Source: (1) EPA, 1990

Table A-13. Design Information and Stack Parameters for Orange Cogeneration Facility-Auxiliary Boiler

Data	Design Operating Conditions (Maximum Capacity, Percent)
	100
General	
Steam Output (lb/hr)	82,993
Heat Input Rate (MMBtu/hr)	100
Hours of Operation	8760
Exhaust Flow Conditions	
Mass Flow Rate (lb/hr)	89,455
Temperature (°F)	305
Moisture Content (% Vol.)	10.39
Natural Gas Consumption (cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)	
Heat Content, LHV (Btu/cf)	946
Natural Gas Consumption (cf/hr)	105,708
Natural Gas Consumption (MMcf/hr)	0.105708
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 ft-lb/°R x (Temp. (°F)+ 460°F)] ÷ ÷ [Molecular weight x 2116.8 lb/ft² x 60 min/hr]	
Mass Flow (lb/hr)	89,455
Temperature (°F)	305
Molecular Weight	28.00
Volume Flow (acfm)	29,731
Volume Flow (dscfm)= Volume flow (acfm) x [(68°F + 460°F)÷(Exhaust Temperature(°F) + 460°F)] x [(100-(Moisture Content(%)) ÷ 100]	
Volume Flow (acfm)	29,731
Exhaust Temperature (°F)	305
Moisture Content (%)	10.39
Volume Flow (dscfm)	18,388
Stack Data	
Stack Height (ft)	65
Diameter (ft)	3.67
Operating Data	
Velocity (ft/sec)= Volume flow (acfm) ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min	
Volume Flow (acfm)	29,731
Diameter (ft)	3.67
Velocity (ft/sec)	46.9

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2.116.8 lb(force)/ft²

Table A-14. Maximum Emissions of Criteria Pollutants for the Orange Cogeneration Facility-Auxiliary Boiler

Pollutant	Design Operating Conditions (Maximum Capacity, Percent)
	100
Particulate Matter (lb/hr)= Emission Factor (lb/MMBtu) x Heat Input Rate (MMBtu/hr)	
Emission Factor, lb/MMBtu	0.010
Heat Input Rate (MMBtu/hr)	100.0
lb/hr	1.00
TPY	4.38
Sulfur Dioxide (lb/hr)= Sulfur Content (gr/100 cf) x [Fuel Consumption (cf/hr) ÷ 100] x 1 lb/7000 gr x (lb SO2/lb S)	
Sulfur content, gr/100 cf	1.0
Fuel Consumption (cf/hr)	105,708
lb SO2/lb S (64/32)	2.0
lb/hr	0.30
TPY	1.32
Nitrogen Oxides (lb/hr)= Emission Factor (lb/MMBtu) x Heat Input Rate (MMBtu/hr)	
Emission Factor (lb/MMBtu)	0.130
Heat Input Rate (MMBtu/hr)	100.0
lb/hr	13.00
TPY	56.94
Carbon Monoxide (lb/hr)= Emission Factor (lb/MMBtu) x Heat Input Rate (MMBtu/hr)	
Emission Factor (lb/MMBtu)	0.100
Heat Input Rate (MMBtu/hr)	100.0
lb/hr	10.00
TPY	43.80
Volatile Organic Compounds (lb/hr)= Emission Factor (lb/MMBtu) x Heat Input Rate (MMBtu/hr)	
Emission Factor (lb/MMBtu)	0.043
Heat Input Rate (MMBtu/hr)	100.0
lb/hr	4.30
TPY	18.83

Table A-15. Maximum Emissions of Other Regulated Pollutants for the Orange Cogeneration Facility Auxiliary Boiler

Pollutant	Design Operating Conditions (Maximum Capacity, Percent)
	100
Arsenic (lb/hr)= Negligible	
Basis, lb/10E+12 Btu	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Beryllium (lb/hr)= Negligible	
Basis, lb/10E+12 Btu	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu	
Basis, lb/10E+12 Btu (1)	0.027
HIR (MMBtu/hr)	100.0
lb/hr	2.70E-06
TPY	1.18E-05
Fluoride (lb/hr)= Negligible	
Basis, lb/10E+12 Btu	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2	
Fraction SO2 (%)	5
SO2 (lb/hr)	0.30
lb H2SO4/lb SO2 (98/64)	1.53
lb/hr	2.31E-02
TPY	1.01E-01

Source: (1) DER, 1992

Table A-16. Maximum Emissions of Non-Regulated Pollutants for the Orange Cogeneration Facility-Auxiliary Boiler

Pollutant	Design Operating Conditions (Maximum Capacity, Percent)
	100
Manganese (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Nickel (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Cadmium (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Chromium (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Copper (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Vanadium (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Selenium (lb/hr)= Negligible	
Basis, lb/10E+12 Btu (1)	NA
HIR (MMBtu/hr)	NA
lb/hr	NA
TPY	NA
Polycyclic Organic Matter (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu	
Basis, lb/10E+12 Btu (1)	1.113
HIR (MMBtu/hr)	100.0
lb/hr	1.11E-04
TPY	4.87E-04
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu	
Basis, lb/10E+12 Btu (1)	88.12
HIR (MMBtu/hr)	100.0
lb/hr	8.81E-03
TPY	3.86E-02

Source: (1) EPA, 1990

Table A-17. Summary of Maximum Pollutant Emissions for the Proposed Orange Cogeneration Facility- Simple Cycle Operation- GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	20 °F			40 °F			59 °F			80 °F			100 °F		
		CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total
PM	lb/hr	5.00E+00	0.00E+00	5.00E+00	5.00E+00	0.00E+00	5.00E+00	5.00E+00	0.00E+00	5.00E+00	5.00E+00	0.00E+00	5.00E+00	5.00E+00	0.00E+00	5.00E+00
	TPY	2.19E+01	0.00E+00	2.19E+01	2.19E+01	0.00E+00	2.19E+01	2.19E+01	0.00E+00	2.19E+01	2.19E+01	0.00E+00	2.19E+01	2.19E+01	0.00E+00	2.19E+01
SO2	lb/hr	1.07E+00	0.00E+00	1.07E+00	1.13E+00	0.00E+00	1.13E+00	1.09E+00	0.00E+00	1.09E+00	9.46E-01	0.00E+00	9.46E-01	8.16E-01	0.00E+00	8.16E-01
	TPY	4.69E+00	0.00E+00	4.69E+00	4.96E+00	0.00E+00	4.96E+00	4.76E+00	0.00E+00	4.76E+00	4.14E+00	0.00E+00	4.14E+00	3.58E+00	0.00E+00	3.58E+00
NOx^a	lb/hr	3.57E+01	0.00E+00	3.57E+01	3.78E+01	0.00E+00	3.78E+01	3.63E+01	0.00E+00	3.63E+01	3.16E+01	0.00E+00	3.16E+01	2.73E+01	0.00E+00	2.73E+01
	TPY	1.57E+02	0.00E+00	1.57E+02	1.66E+02	0.00E+00	1.66E+02	1.59E+02	0.00E+00	1.59E+02	1.39E+02	0.00E+00	1.39E+02	1.19E+02	0.00E+00	1.19E+02
CO	lb/hr	2.85E+01	0.00E+00	2.85E+01	2.84E+01	0.00E+00	2.84E+01	2.68E+01	0.00E+00	2.68E+01	2.41E+01	0.00E+00	2.41E+01	2.13E+01	0.00E+00	2.13E+01
	TPY	1.25E+02	0.00E+00	1.25E+02	1.24E+02	0.00E+00	1.24E+02	1.18E+02	0.00E+00	1.18E+02	1.05E+02	0.00E+00	1.05E+02	9.32E+01	0.00E+00	9.32E+01
VOC	lb/hr	4.07E+00	0.00E+00	4.07E+00	4.05E+00	0.00E+00	4.05E+00	3.83E+00	0.00E+00	3.83E+00	3.44E+00	0.00E+00	3.44E+00	3.04E+00	0.00E+00	3.04E+00
	TPY	1.78E+01	0.00E+00	1.78E+01	1.78E+01	0.00E+00	1.78E+01	1.68E+01	0.00E+00	1.68E+01	1.51E+01	0.00E+00	1.51E+01	1.33E+01	0.00E+00	1.33E+01
Sulfuric	lb/hr	8.19E-02	0.00E+00	8.19E-02	8.67E-02	0.00E+00	8.67E-02	8.32E-02	0.00E+00	8.32E-02	7.24E-02	0.00E+00	7.24E-02	6.25E-02	0.00E+00	6.25E-02
Acid Mist	TPY	3.59E-01	0.00E+00	3.59E-01	3.80E-01	0.00E+00	3.80E-01	3.64E-01	0.00E+00	3.64E-01	3.17E-01	0.00E+00	3.17E-01	2.74E-01	0.00E+00	2.74E-01
POM	lb/hr	3.94E-04	0.00E+00	3.94E-04	4.17E-04	0.00E+00	4.17E-04	4.00E-04	0.00E+00	4.00E-04	3.49E-04	0.00E+00	3.49E-04	3.01E-04	0.00E+00	3.01E-04
	TPY	1.73E-03	0.00E+00	1.73E-03	1.83E-03	0.00E+00	1.83E-03	1.75E-03	0.00E+00	1.75E-03	1.53E-03	0.00E+00	1.53E-03	1.32E-03	0.00E+00	1.32E-03
Formaldehyde	lb/hr	3.12E-02	0.00E+00	3.12E-02	3.30E-02	0.00E+00	3.30E-02	3.17E-02	0.00E+00	3.17E-02	2.76E-02	0.00E+00	2.76E-02	2.38E-02	0.00E+00	2.38E-02
	TPY	1.37E-01	0.00E+00	1.37E-01	1.45E-01	0.00E+00	1.45E-01	1.39E-01	0.00E+00	1.39E-01	1.21E-01	0.00E+00	1.21E-01	1.04E-01	0.00E+00	1.04E-01

Note: CT = 1 combustion turbine; AB = auxiliary boiler (not in operation). All units operating for 8,760 hours per year.

^a NOx emission is based on 25 ppmvd, corrected to 15 % O2.

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Table A-18. Summary of Maximum Polllutant Emissions for the Proposed Orange Cogeneration Facility-
Combined Cycle Operation- GE LM6000-PA, Natural Gas, Water Injection

Pollutant	Units	20 °F			40 °F			59 °F			80 °F			100 °F		
		CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total
PM	lb/hr	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01
	TPY	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01
SO2	lb/hr	2.14E+00	3.02E-01	2.44E+00	2.26E+00	3.02E-01	2.57E+00	2.17E+00	3.02E-01	2.48E+00	1.89E+00	3.02E-01	2.19E+00	1.63E+00	3.02E-01	1.93E+00
	TPY	9.37E+00	1.32E+00	1.07E+01	9.92E+00	1.32E+00	1.12E+01	9.52E+00	1.32E+00	1.08E+01	8.29E+00	1.32E+00	9.61E+00	7.15E+00	1.32E+00	8.47E+00
NOx^a	lb/hr	7.15E+01	1.30E+01	8.45E+01	7.57E+01	1.30E+01	8.87E+01	7.26E+01	1.30E+01	8.56E+01	6.32E+01	1.30E+01	7.62E+01	5.46E+01	1.30E+01	6.76E+01
	TPY	3.13E+02	5.69E+01	3.70E+02	3.31E+02	5.69E+01	3.88E+02	3.18E+02	5.69E+01	3.75E+02	2.77E+02	5.69E+01	3.34E+02	2.39E+02	5.69E+01	2.96E+02
CO	lb/hr	5.70E+01	1.00E+01	6.70E+01	5.68E+01	1.00E+01	6.68E+01	5.37E+01	1.00E+01	6.37E+01	4.82E+01	1.00E+01	5.82E+01	4.26E+01	1.00E+01	5.26E+01
	TPY	2.50E+02	4.38E+01	2.93E+02	2.49E+02	4.38E+01	2.92E+02	2.35E+02	4.38E+01	2.79E+02	2.11E+02	4.38E+01	2.55E+02	1.86E+02	4.38E+01	2.30E+02
VOC	lb/hr	8.14E+00	4.30E+00	1.24E+01	8.11E+00	4.30E+00	1.24E+01	7.67E+00	4.30E+00	1.20E+01	6.88E+00	4.30E+00	1.12E+01	6.08E+00	4.30E+00	1.04E+01
	TPY	3.57E+01	1.88E+01	5.45E+01	3.55E+01	1.88E+01	5.43E+01	3.36E+01	1.88E+01	5.24E+01	3.01E+01	1.88E+01	4.90E+01	2.66E+01	1.88E+01	4.55E+01
Sulfuric Acid Mist	lb/hr	1.64E-01	2.31E-02	1.87E-01	1.73E-01	2.31E-02	1.96E-01	1.66E-01	2.31E-02	1.90E-01	1.45E-01	2.31E-02	1.68E-01	1.25E-01	2.31E-02	1.48E-01
	TPY	7.18E-01	1.01E-01	8.19E-01	7.59E-01	1.01E-01	8.61E-01	7.29E-01	1.01E-01	8.30E-01	6.35E-01	1.01E-01	7.36E-01	5.48E-01	1.01E-01	6.49E-01
POM	lb/hr	7.89E-04	1.11E-04	9.00E-04	8.34E-04	1.11E-04	9.46E-04	8.01E-04	1.11E-04	9.12E-04	6.97E-04	1.11E-04	8.09E-04	6.02E-04	1.11E-04	7.13E-04
	TPY	3.45E-03	4.87E-04	3.94E-03	3.65E-03	4.87E-04	4.14E-03	3.51E-03	4.87E-04	4.00E-03	3.05E-03	4.87E-04	3.54E-03	2.64E-03	4.87E-04	3.12E-03
Formaldehyde	lb/hr	6.24E-02	8.81E-03	7.13E-02	6.61E-02	8.81E-03	7.49E-02	6.34E-02	8.81E-03	7.22E-02	5.52E-02	8.81E-03	6.40E-02	4.76E-02	8.81E-03	5.65E-02
	TPY	2.74E-01	3.86E-02	3.12E-01	2.89E-01	3.86E-02	3.28E-01	2.78E-01	3.86E-02	3.16E-01	2.42E-01	3.86E-02	2.80E-01	2.09E-01	3.86E-02	2.47E-01

Note: CT = 2 combustion turbines; AB = auxiliary boiler. All units operating for 8,760 hours per year.

^a NOx emission is based on 25 ppmvd, corrected to 15 % O2.

Table A-19. Summary of Maximum Pollutant Emissions for the Proposed Orange Cogeneration Facility- Combined Cycle Operation- GE LM6000-PA, Natural Gas, Dry Low NOx

Pollutant	Units	20 °F			40 °F			59 °F			80 °F			100 °F		
		CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total	CT	AB	Total
PM	lb/hr	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01	1.00E+01	1.00E+00	1.10E+01
	TPY	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01	4.38E+01	4.38E+00	4.82E+01
SO2	lb/hr	2.06E+00	3.02E-01	2.36E+00	2.15E+00	3.02E-01	2.45E+00	2.06E+00	3.02E-01	2.36E+00	1.82E+00	3.02E-01	2.12E+00	1.57E+00	3.02E-01	1.88E+00
	TPY	9.00E+00	1.32E+00	1.03E+01	9.42E+00	1.32E+00	1.07E+01	9.03E+00	1.32E+00	1.03E+01	7.97E+00	1.32E+00	9.29E+00	6.90E+00	1.32E+00	8.22E+00
NOx^a	lb/hr	6.94E+01	1.30E+01	8.24E+01	7.26E+01	1.30E+01	8.56E+01	6.96E+01	1.30E+01	8.26E+01	6.14E+01	1.30E+01	7.44E+01	5.31E+01	1.30E+01	6.61E+01
	TPY	3.04E+02	5.69E+01	3.61E+02	3.18E+02	5.69E+01	3.75E+02	3.05E+02	5.69E+01	3.62E+02	2.69E+02	5.69E+01	3.26E+02	2.33E+02	5.69E+01	2.90E+02
CO	lb/hr	5.72E+01	1.00E+01	6.72E+01	5.67E+01	1.00E+01	6.67E+01	5.40E+01	1.00E+01	6.40E+01	4.86E+01	1.00E+01	5.86E+01	4.29E+01	1.00E+01	5.29E+01
	TPY	2.51E+02	4.38E+01	2.94E+02	2.48E+02	4.38E+01	2.92E+02	2.36E+02	4.38E+01	2.80E+02	2.13E+02	4.38E+01	2.57E+02	1.88E+02	4.38E+01	2.31E+02
VOC	lb/hr	8.17E+00	4.30E+00	1.25E+01	8.09E+00	4.30E+00	1.24E+01	7.71E+00	4.30E+00	1.20E+01	6.94E+00	4.30E+00	1.12E+01	6.12E+00	4.30E+00	1.04E+01
	TPY	3.58E+01	1.88E+01	5.46E+01	3.55E+01	1.88E+01	5.43E+01	3.38E+01	1.88E+01	5.26E+01	3.04E+01	1.88E+01	4.92E+01	2.68E+01	1.88E+01	4.56E+01
Sulfuric	lb/hr	1.57E-01	2.31E-02	1.81E-01	1.65E-01	2.31E-02	1.88E-01	1.58E-01	2.31E-02	1.81E-01	1.39E-01	2.31E-02	1.62E-01	1.21E-01	2.31E-02	1.44E-01
Acid Mist	TPY	6.89E-01	1.01E-01	7.91E-01	7.21E-01	1.01E-01	8.23E-01	6.91E-01	1.01E-01	7.92E-01	6.10E-01	1.01E-01	7.11E-01	5.28E-01	1.01E-01	6.29E-01
POM	lb/hr	7.89E-04	1.11E-04	9.00E-04	8.34E-04	1.11E-04	9.46E-04	8.01E-04	1.11E-04	9.12E-04	6.97E-04	1.11E-04	8.09E-04	6.02E-04	1.11E-04	7.13E-04
	TPY	3.45E-03	4.87E-04	3.94E-03	3.65E-03	4.87E-04	4.14E-03	3.51E-03	4.87E-04	4.00E-03	3.05E-03	4.87E-04	3.54E-03	2.64E-03	4.87E-04	3.12E-03
Formaldehyde	lb/hr	6.24E-02	8.81E-03	7.13E-02	6.61E-02	8.81E-03	7.49E-02	6.34E-02	8.81E-03	7.22E-02	5.52E-02	8.81E-03	6.40E-02	4.76E-02	8.81E-03	5.65E-02
	TPY	2.74E-01	3.86E-02	3.12E-01	2.89E-01	3.86E-02	3.28E-01	2.78E-01	3.86E-02	3.16E-01	2.42E-01	3.86E-02	2.80E-01	2.09E-01	3.86E-02	2.47E-01

Note: CT = 2 combustion turbines; AB = auxiliary boiler. All units operating for 8,760 hours per year.

^a NOx emission is based on 25 ppmvd, corrected to 15 % O2.

EPA-450/2-90-011

October 1990

TOXIC AIR POLLUTANT EMISSION FACTORS - A COMPILATION FOR SELECTED AIR TOXIC COMPOUNDS AND SOURCES, SECOND EDITION

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Municipal waste combustion	4953	Mass burn waterwall combustor, small size new model to any age medium	501001	Tetrachlorodibenzo-p-dioxins, total		3.2 x 10E-8 lb/ton feed	Capacity < 600 tons/day, ESP control only, overall average of several source averages, range is 1.26 x 10E-8 - 5.2 x 10E-8 lb/ton	180
Municipal waste combustion	4953	Mass burn waterwall combustor, small size new model to any age medium	501001	Tetrachlorodibenzo-p-dioxins, total		0.74 ug/Mg feed	Capacity < 600 tons/day, spray drying after acid gas and PM control, one data point only	180
Municipal waste combustion	4953	Mass burn waterwall combustor, small size new model to any age medium	501001	Tetrachlorodibenzo-p-dioxins, total		2.0 x 10E-8 lb/ton feed	Capacity < 600 tons/day, dry sorbent injection after acid gas and PM control, range is 1.08 x 10E-8 - 2.4 x 10E-8 lb/ton	180
Municipal waste combustion	4953	Mass burn waterwall combustor, built before 1980	501001	Tetrachlorodibenzo-p-dioxins, total		2.8 x 10E-6 lb/ton feed	ESP control only, overall average of several source averages, range is 6.4 x 10E-8 - 6.0 x 10E-6 lb/ton	180
Municipal waste combustion	4953	Mass burn, refractory facility	501001	Tetrachlorodibenzo-p-dioxins, total		3.4 x 10E-6 lb/ton feed	ESP control only, overall average of several source averages, range is 3.0 x 10E-6 - 3.6 x 10E-6 lb/ton	180
Municipal waste combustion	4953	Incinerator stack	501001	Zinc	7440666	1.0 lb/ton munic. solid waste-dry wt.	Controlled by spray-baffle scrubber, based on material balance for model incinerator	98
Naphthalene production		Process emissions		Naphthalene	91203	0.478 lb/ton naphthalene produced	Based on POM emissions and 87% naphthalene	99
Naphthalene production		Storage		Naphthalene	91203	0.0454 lb/ton produced	Based on data from State files and engineering judgement	99
Natural gas combustion		Commercial boiler	10300601	Ammonia	7664417	0.49 lb/10E6 cubic feet gas burned	Sources emitting > 100 tons NH3/year	179
Natural gas combustion		Industrial boilers	10200401	Ammonia	7664417	3.2 lbs/10E6 cubic feet gas burned	Sources emitting > 100 tons NH3/year	179
Natural gas combustion		Boilers, exhaust system	102006	Benzene	71432	1.18% by vol (or 4% by wt) of total VOC	South Coast study, California, engineering judgement	132
Natural gas combustion		Commercial/institutional	103006	Formaldehyde	50000	220.3 lb/10E12 Btu heat input	Control status unspecified, based on source tests	106
Natural gas combustion		Domestic		Formaldehyde	50000	997 lb/10E12 Btu heat input	Control status unspecified, based on source tests	106
Natural gas combustion		Industrial	102006	Formaldehyde	50000	88.12 lb/10E12 Btu heat input	Control status unspecified, based on source tests	106
Natural gas combustion		Double shell boilers, home heating		Polycyclic organic matter		1.113 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion		Firetube boiler, process heater	10200401	Polycyclic organic matter		0.649 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114

MERCURY EMISSIONS TO THE ATMOSPHERE IN FLORIDA

FINAL REPORT

Prepared For:

Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399

Prepared By:

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1034 NW 57th Street
Gainesville, Florida 32605

August 1992
91166C1

Table 2.2-2. Mercury Emission Factors Used for Florida Electric Utility Sources

Fuel	Removal	Units	Emission Factor Low	Average	High
Coal-Uncontrolled	NA	lb/10^{12} Btu [a]	10	16	21
		lb/Mton	0.25	0.42	0.546
w/ESP	25%	lb/10^{12} Btu	7.2	12.0	15.6
		lb/Mton	0.19	0.32	0.41
w/Scrubber	70%	lb/10^{12} Btu	2.9	4.8	6.3
		lb/Mton	0.08	0.13	0.16
Residual Oil	NA	lb/10^{12} Btu	0.4	3.6	9.3
		lb/10^3 gal [b]	5.79E-05	5.46E-04	1.41E-03
Distillate Oil	NA	lb/10^{12} Btu	0.4	3.4	8.8
		lb/10^3 gal [c]	4.99E-05	4.71E-04	1.21E-03
Natural Gas	NA	lb/10^{12} Btu [d]	0.001	0.014	0.027
		lb/MMcf	1.25E-06	1.44E-05	2.75E-05

Note: NA = not applicable.
Units: M = 1,000

[a] Calculated based on 13,100 Btu/lb coal.
[b] Calculated based on 18,500 Btu/lb and 8.2 lb/gal.
[c] Calculated based on 19,500 Btu/lb and 7.1 lb/gal.
[d] Calculated based on 1,024 Btu/scf.

Source: KBN, 1992.

APPENDIX B

ISCST MODEL RESULTS SUMMARY

Summary of Screening Air Dispersion Impacts for the Orange Cogeneration Facility, Bartow, Florida; Simple Cycle Operation
(Three Ambient Temperatures)

OCSSGENR
06/22/93

Ambient Temperature (°F)	Number of Units	Pollutant	Emission Rate Basis		Per Unit Emission Rate		Total Facility Emission Rate			Modeled Emission Rate (g/s)	Averaging Period	Generic Modeled Conc (μg/m³)	Actual Conc (μg/m³)	EPA Sig. Values (μg/m³)
			Rate	Units	Rate	Units	Rate	Units	(g/s)					
20	1	Particulate	5	lb/hr	5.0	lb/hr	5.0	lb/hr	0.63	10.00	24-hour	23.40	1.47	5
											Annual	0.094	0.0059	1
		Nitrogen Dioxide	25	ppm	156.5	TPY	156.5	TPY	4.50	10.00	Annual	0.094	0.042	1
		Carbon Monoxide	30	ppm	28.5	lb/hr	28.5	lb/hr	3.59	10.00	1-hour	185.2	66.51	2000
											8-hour	51.6	18.53	500
40	1	Particulate	5	lb/hr	5.0	lb/hr	5.0	lb/hr	0.63	10.00	24-hour	18.10	1.14	5
											Annual	0.087	0.0055	1
		Nitrogen Dioxide	25	ppm	165.7	TPY	165.7	TPY	4.77	10.00	Annual	0.087	0.041	1
		Carbon Monoxide	30	ppm	28.4	lb/hr	28.4	lb/hr	3.58	10.00	1-hour	165.20	59.12	2000
											8-hour	41.4	14.81	500
100	1	Particulate	5	lb/hr	5.0	lb/hr	5.0	lb/hr	0.63	10.00	24-hour	54.20	3.41	5
											Annual	0.20	0.013	1
		Nitrogen Dioxide	25	ppm	119.5	TPY	119.5	TPY	3.44	10.00	Annual	0.20	0.069	1
		Carbon Monoxide	30	ppm	21.3	lb/hr	21.3	lb/hr	2.68	10.00	1-hour	262.2	70.37	2000
											8-hour	101.9	27.35	500

Note: All stack parameters and emission rates apply to the CT operating in simple cycle mode with water injection using natural gas.

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCSSGENR.082
ISCST2 OUTPUT FILE NUMBER 2 :OCSSGENR.083
ISCST2 OUTPUT FILE NUMBER 3 :OCSSGENR.084
ISCST2 OUTPUT FILE NUMBER 4 :OCSSGENR.085
ISCST2 OUTPUT FILE NUMBER 5 :OCSSGENR.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / SIMPLE CYCLE / GENERIC EMISSIONS 10 G/S
Second title for first output file is 20,40, and 100 DEG / 60' CT STACK

20° F

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: GSS020					
Annual					
	1982	0.09044	240.	9000.	82------
	1983	0.06770	250.	7000.	83------
	1984	0.09431	240.	8000.	84------
	1985	0.08706	240.	9000.	85------
	1986	0.08504	90.	3000.	86------
HIGH 1-Hour					
	1982	154.44221	150.	106.	82011414
	1983	185.19388	90.	91.	83032414
	1984	144.28180	110.	97.	84032908
	1985	73.47141	360.	140.	85083119
	1986	59.64932	340.	94.	86031412
HSH 1-Hour					
	1982	52.79645	130.	200.	82011415
	1983	75.60313	280.	184.	83022712
	1984	120.47332	150.	106.	84022811
	1985	42.89340	20.	149.	85083117
	1986	7.12177	110.	100.	86012711
HIGH 3-Hour					
	1982	73.16328	140.	119.	82011415
	1983	66.30235	90.	91.	83032415
	1984	94.83561	150.	106.	84022812
	1985	28.56992	360.	140.	85083121
	1986	19.88311	340.	94.	86031412
HSH 3-Hour					
	1982	9.57439	130.	119.	82011418
	1983	25.21534	280.	184.	83022712
	1984	45.71914	140.	119.	84032912
	1985	17.44268	130.	119.	85021218
	1986	3.10454	230.	10000.	86032706
HIGH 8-Hour					
	1982	28.00793	140.	119.	82011416
	1983	29.35867	280.	184.	83022716
	1984	51.59492	150.	106.	84022816
	1985	12.71086	20.	149.	85083116
	1986	7.45617	340.	94.	86031416
HSH 8-Hour					
	1982	2.42431	140.	119.	82011424
	1983	6.01550	90.	91.	83031724
	1984	30.58204	140.	119.	84032916
	1985	6.54659	130.	119.	85021224
	1986	1.84591	90.	2500.	86100516
HIGH 24-Hour					
	1982	10.14408	140.	119.	82011424
	1983	9.78623	280.	184.	83022724

1984	23.36542	150.	106.	84022824
1985	6.33263	20.	149.	85083124
1986	2.59345	340.	94.	86031424

HSH 24-Hour

1982	0.77859	240.	3000.	82082924
1983	2.00517	90.	91.	83031724
1984	10.25467	140.	119.	84032924
1985	0.78318	120.	7000.	85021224
1986	0.75215	90.	3000.	86040824

SOURCE GROUP ID: GSS040 40 °F

Annual

1982	0.08372	240.	9000.	82------
1983	0.06292	240.	8000.	83------
1984	0.08699	240.	8000.	84------
1985	0.08034	240.	10000.	85------
1986	0.07803	90.	3000.	86------

HIGH 1-Hour

1982	129.31621	150.	106.	82011414
1983	165.15565	90.	91.	83032414
1984	120.22223	110.	97.	84032908
1985	56.07795	360.	140.	85083119
1986	44.30790	340.	94.	86031412

HSH 1-Hour

1982	43.81917	130.	200.	82011415
1983	58.17887	280.	184.	83022712
1984	97.56460	150.	106.	84022811
1985	31.41789	20.	149.	85083117
1986	5.16054	100.	1000.	86080112

HIGH 3-Hour

1982	60.93316	140.	119.	82011415
1983	58.11613	90.	91.	83032415
1984	76.08755	150.	106.	84022812
1985	21.40800	360.	140.	85083121
1986	14.76930	340.	94.	86031412

HSH 3-Hour

1982	5.97315	130.	119.	82011418
1983	19.39811	280.	184.	83022712
1984	34.89723	140.	119.	84032912
1985	12.13949	130.	119.	85021215
1986	2.90621	230.	10000.	86032706

HIGH 8-Hour

1982	23.20721	140.	119.	82011416
1983	24.59791	280.	184.	83022716
1984	41.44559	150.	106.	84022816
1985	9.37802	20.	149.	85083116
1986	5.53849	340.	94.	86031416

HSH 8-Hour

1982	1.56001	360.	2500.	82082716
1983	3.97531	90.	91.	83031724
1984	22.35923	140.	119.	84032916
1985	4.76691	130.	119.	85021224
1986	1.68468	90.	3000.	86100516

HIGH 24-Hour

1982	8.24165	140.	119.	82011424
1983	8.19930	280.	184.	83022724
1984	18.13896	150.	106.	84022824
1985	4.62480	20.	149.	85083124
1986	1.92643	340.	94.	86031424

HSH 24-Hour

1982	0.71859	240.	3000.	82082924

1983	1.32510	90.	91.	83031724
1984	7.47854	140.	119.	84032924
1985	0.71667	120.	7000.	85021224
1986	0.70370	90.	3000.	86040824

SOURCE GROUP ID: GSS100

100 °F

Annual

1982	0.10095	240.	8000.	82------
1983	0.07879	100.	93.	83------
1984	0.20368	140.	119.	84------
1985	0.09606	240.	9000.	85------
1986	0.09200	90.	3000.	86------

HIGH 1-Hour

1982	262.19177	150.	106.	82011414
1983	258.46442	90.	91.	83032414
1984	245.76088	110.	97.	84032908
1985	158.52286	360.	140.	85083119
1986	147.63962	340.	94.	86031412

HSH 1-Hour

1982	87.90906	130.	200.	82011415
1983	161.78177	280.	184.	83022712
1984	225.89149	150.	106.	84022811
1985	103.41029	20.	149.	85083117
1986	41.70058	110.	100.	86012711

HIGH 3-Hour

1982	124.44328	140.	119.	82011415
1983	105.48948	90.	91.	83032415
1984	185.65222	150.	106.	84022812
1985	67.97526	140.	119.	85021215
1986	49.21321	340.	94.	86031412

HSH 3-Hour

1982	38.94577	130.	119.	82011418
1983	55.37284	90.	91.	83031724
1984	107.61301	140.	119.	84032912
1985	45.62215	130.	119.	85021218
1986	15.88226	110.	100.	86012715

HIGH 8-Hour

1982	48.98525	140.	119.	82011416
1983	51.12876	280.	184.	83022716
1984	101.93536	150.	106.	84022816
1985	36.04826	140.	119.	85021216
1986	18.45495	340.	94.	86031416

HSH 8-Hour

1982	9.80539	140.	119.	82011424
1983	20.76481	90.	91.	83031724
1984	68.83555	140.	119.	84022816
1985	17.40616	130.	119.	85021224
1986	5.82260	150.	106.	86012724

HIGH 24-Hour

1982	19.59688	140.	119.	82011424
1983	17.04990	280.	184.	83022724
1984	54.16481	150.	106.	84022824
1985	19.13910	130.	119.	85021224
1986	6.41911	340.	94.	86031424

HSH 24-Hour

1982	1.19343	260.	184.	82061524
1983	6.92160	90.	91.	83031724
1984	28.50564	140.	119.	84032924
1985	2.56146	140.	119.	85010424
1986	2.14240	150.	106.	86012724

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCWIPM.082
ISCST2 OUTPUT FILE NUMBER 2 :OCWIPM.083
ISCST2 OUTPUT FILE NUMBER 3 :OCWIPM.084
ISCST2 OUTPUT FILE NUMBER 4 :OCWIPM.085
ISCST2 OUTPUT FILE NUMBER 5 :OCWIPM.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-WATER INJECTION / PM
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.08267	250.	1000.	82------
	1983	0.06294	250.	1000.	83------
	1984	0.07632	240.	1500.	84------
	1985	0.06969	70.	1000.	85------
	1986	0.08058	90.	1000.	86------
HIGH 24-Hour					
	1982	0.92654	120.	200.	82011424
	1983	1.45181	290.	200.	83022724
	1984	2.56726	130.	200.	84022824
	1985	2.38860	360.	200.	85083124
	1986	0.83515	300.	210.	86031324
HSH 24-Hour					
	1982	0.77915	290.	200.	82120124
	1983	1.18654	110.	200.	83020324
	1984	1.27560	120.	200.	84022824
	1985	0.91056	120.	400.	85010424
	1986	0.81211	300.	210.	86031824
SOURCE GROUP ID: ALL059					
Annual					
	1982	0.08508	250.	1000.	82------
	1983	0.06484	250.	1000.	83------
	1984	0.07874	240.	1500.	84------
	1985	0.07229	70.	1000.	85------
	1986	0.08374	90.	1000.	86------
HIGH 24-Hour					
	1982	0.94803	120.	200.	82011424
	1983	1.61343	290.	193.	83022724
	1984	2.62976	130.	200.	84022824
	1985	2.45507	360.	200.	85083124
	1986	0.83515	300.	210.	86031324
HSH 24-Hour					
	1982	0.77915	290.	200.	82120124
	1983	1.27563	110.	200.	83020324
	1984	1.30729	120.	200.	84022824
	1985	1.38883	120.	200.	85010424
	1986	0.81211	300.	210.	86031824
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.10047	250.	1000.	82------
	1983	0.07473	250.	1000.	83------
	1984	0.09134	240.	1500.	84------
	1985	0.08582	80.	1000.	85------
	1986	0.09941	90.	1000.	86------
HIGH 24-Hour					

40° F ALL SOURCES

59 °F

100 °F

1982	1.56366	240.	183.	82042324
1983	2.34028	290.	193.	83022724
1984	$\boxed{3.43134}$	130.	200.	84022824
1985	2.90536	120.	200.	85010424
1986	1.19577	230.	200.	86010824

HSH 24-Hour

1982	1.40756	240.	183.	82032824
1983	1.82606	100.	200.	83042424
1984	1.67573	120.	106.	84022824
1985	2.56048	120.	200.	85021224
1986	0.84785	300.	210.	86031824

SOURCE GROUP ID: CT040

40°F CT ONLY

Annual

1982	0.04843	240.	2500.	82------
1983	0.03452	240.	2500.	83------
1984	0.04509	240.	2500.	84------
1985	0.04537	80.	1500.	85------
1986	0.05453	90.	1500.	86------

HIGH 24-Hour

1982	0.84757	120.	200.	82011424
1983	1.16574	110.	200.	83042424
1984	2.44159	130.	200.	84022824
1985	2.37983	360.	200.	85083124
1986	0.62733	130.	200.	86030124

HSH 24-Hour

1982	0.50632	240.	1500.	82082924
1983	1.08294	110.	200.	83020324
1984	1.22520	120.	200.	84022824
1985	0.73004	120.	200.	85010424
1986	0.57872	130.	200.	86012724

SOURCE GROUP ID: CT059

59°F CT ONLY

Annual

1982	0.05066	240.	2500.	82------
1983	0.03642	240.	2000.	83------
1984	0.04731	240.	2000.	84------
1985	0.04790	70.	1000.	85------
1986	0.05678	90.	1500.	86------

HIGH 24-Hour

1982	0.86906	120.	200.	82011424
1983	1.26649	110.	200.	83042424
1984	2.50408	130.	200.	84022824
1985	2.44630	360.	200.	85083124
1986	0.64865	130.	200.	86030124

HSH 24-Hour

1982	0.52443	240.	1500.	82082924
1983	1.17202	110.	200.	83020324
1984	1.25824	120.	106.	84022824
1985	1.23738	120.	200.	85010424
1986	0.59914	130.	200.	86012724

SOURCE GROUP ID: CT100

100°F CT ONLY

Annual

1982	0.06355	240.	2000.	82------
1983	0.04505	240.	2000.	83------
1984	0.05864	240.	2000.	84------
1985	0.06112	80.	1000.	85------
1986	0.07080	90.	1000.	86------

HIGH 24-Hour

1982	1.56366	240.	183.	82042324
1983	1.94624	100.	200.	83031824
1984	3.30567	130.	200.	84022824

	1985	2.83316	360.	200.	85083124
	1986	1.19577	230.	200.	86010824
H 24-Hour					
	1982	1.40756	240.	183.	82032824
	1983	1.68144	100.	200.	83042424
	1984	1.66936	120.	106.	84022824
	1985	2.41983	120.	200.	85021224
	1986	0.71988	130.	200.	86012724
SOURCE GROUP ID:	AUXBLR				
nual					
	1982	0.05687	290.	200.	82------
	1983	0.04732	290.	200.	83------
	1984	0.04514	250.	800.	84------
	1985	0.04435	70.	400.	85------
	1986	0.05285	80.	400.	86------
IGH 24-Hour					
	1982	0.84948	300.	210.	82122424
	1983	0.93817	300.	210.	83030524
	1984	0.79311	300.	210.	84022624
	1985	0.89812	300.	210.	85083024
	1986	0.83515	300.	210.	86031324
HSH 24-Hour					
	1982	0.77915	290.	200.	82120124
	1983	0.64075	300.	210.	83020124
	1984	0.73540	300.	210.	84030524
	1985	0.61206	300.	210.	85112124
	1986	0.81211	300.	210.	86031824

AUX. BLR.

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
ISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCWINOX.082
CST2 OUTPUT FILE NUMBER 2 :OCWINOX.083
CST2 OUTPUT FILE NUMBER 3 :OCWINOX.084
ISCST2 OUTPUT FILE NUMBER 4 :OCWINOX.085
CST2 OUTPUT FILE NUMBER 5 :OCWINOX.086
rst title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-WATER INJECTION / NO2
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)	
SOURCE GROUP ID: ALL040						40°F ALL SOURCES
Annual						
	1982	0.87495	250.	1000.	82------	
	1983	0.66418	250.	1000.	83------	
	1984	0.77046	250.	1000.	84------	
	1985	0.69116	250.	1000.	85------	
	1986	0.76842	90.	800.	86------	
SOURCE GROUP ID: ALL059						59°F
Annual						
	1982	0.88242	250.	1000.	82------	
	1983	0.67023	250.	1000.	83------	
	1984	0.77676	250.	1000.	84------	
	1985	0.69749	250.	1000.	85------	
	1986	0.77815	90.	800.	86------	
SOURCE GROUP ID: ALL100						100°F
Annual						
	1982	0.90262	250.	1000.	82------	
	1983	0.68826	290.	200.	83------	
	1984	0.78191	250.	1000.	84------	
	1985	0.70671	250.	1000.	85------	
	1986	0.78457	90.	800.	86------	
SOURCE GROUP ID: CT040						40°F CT ONLY
Annual						
	1982	0.36594	240.	2500.	82------	
	1983	0.26082	240.	2500.	83------	
	1984	0.34068	240.	2500.	84------	
	1985	0.34277	80.	1500.	85------	
	1986	0.41200	90.	1500.	86------	
SOURCE GROUP ID: CT059						59°F
Annual						
	1982	0.36747	240.	2500.	82------	
	1983	0.26416	240.	2000.	83------	
	1984	0.34315	240.	2000.	84------	
	1985	0.34749	70.	1000.	85------	
	1986	0.41188	90.	1500.	86------	
SOURCE GROUP ID: CT100						100°F
Annual						
	1982	0.34702	240.	2000.	82------	
	1983	0.24600	240.	2000.	83------	
	1984	0.32021	240.	2000.	84------	
	1985	0.33372	80.	1000.	85------	
	1986	0.38657	90.	1000.	86------	
SOURCE GROUP ID: AUXBLR						AUX. BLR.
Annual						
	1982	0.71747	290.	200.	82------	
	1983	0.59700	290.	200.	83------	

1984	0.56945	250.	800.	84------
1985	0.55944	70.	400.	85------
1986	0.66668	80.	400.	86------

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCWICO.082
ISCST2 OUTPUT FILE NUMBER 2 :OCWICO.083
ISCST2 OUTPUT FILE NUMBER 3 :OCWICO.084
ISCST2 OUTPUT FILE NUMBER 4 :OCWICO.085
ISCST2 OUTPUT FILE NUMBER 5 :OCWICO.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-WATER INJECTION / CO
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
HIGH 1-Hour					
	1982	36.62535	120.	200.	82011415
	1983	58.38681	290.	193.	83070622
	1984	39.98288	220.	200.	84081704
	1985	44.84493	190.	200.	85031006
	1986	37.07120	10.	200.	86031412
HSH 1-Hour					
	1982	30.88519	120.	200.	82011413
	1983	55.29050	290.	200.	83022712
	1984	35.65929	100.	200.	84041613
	1985	40.56778	190.	200.	85012306
	1986	31.56118	300.	210.	86031823
HIGH 8-Hour					
	1982	15.17585	300.	210.	82122416
	1983	26.82116	290.	193.	83022716
	1984	26.92858	120.	200.	84032916
	1985	22.35588	360.	200.	85083116
	1986	15.55304	300.	210.	86031308
HSH 8-Hour					
	1982	12.66530	300.	210.	82121516
	1983	12.61085	110.	200.	83042416
	1984	19.69659	130.	200.	84022808
	1985	12.45903	30.	162.	85083124
	1986	15.31325	300.	210.	86031824
SOURCE GROUP ID: ALL059					
HIGH 1-Hour					
	1982	47.86941	290.	200.	82013011
	1983	57.80543	290.	193.	83070622
	1984	38.80351	220.	200.	84081704
	1985	44.00381	190.	200.	85031006
	1986	35.90173	10.	200.	86031412
HSH 1-Hour					
	1982	29.86980	120.	200.	82011413
	1983	54.28680	290.	200.	83022712
	1984	35.10567	100.	200.	84041613
	1985	39.87309	190.	200.	85012306
	1986	31.56118	300.	210.	86031823
HIGH 8-Hour					
	1982	15.17585	300.	210.	82122416
	1983	28.62789	290.	193.	83022716
	1984	26.17939	120.	200.	84032916
	1985	21.65367	360.	200.	85083116
	1986	15.55304	300.	210.	86031308
HSH 8-Hour					
	1982	13.01664	300.	210.	82121516

40°F ALL SOURCES

59°F

1983	13.17905	110.	200.	83042416
1984	19.16915	130.	200.	84022808
1985	12.63220	120.	200.	85021216
1986	15.31325	300.	210.	86031824

SOURCE GROUP ID: ALL100 — 100 °F

HIGH 1-Hour

1982	46.28763	290.	200.	82013011
1983	$\boxed{55.72725}$	290.	193.	83070622
1984	44.78695	290.	200.	84102020
1985	44.24531	290.	200.	85041823
1986	33.19429	10.	142.	86031412

HSH 1-Hour

1982	44.42138	290.	200.	82051021
1983	53.90086	290.	200.	83051424
1984	44.42138	290.	200.	84102024
1985	39.29859	290.	200.	85112020
1986	31.75222	300.	210.	86031823

HIGH 8-Hour

1982	19.90525	290.	200.	82122424
1983	$\boxed{27.65517}$	290.	193.	83022716
1984	24.06155	120.	200.	84032916
1985	19.91609	360.	200.	85083116
1986	15.77560	300.	210.	86031308

HSH 8-Hour

1982	15.12149	290.	200.	82120124
1983	13.39733	120.	200.	83020316
1984	17.59592	130.	200.	84022808
1985	14.15406	120.	200.	85110516
1986	15.76922	300.	210.	86031824

SOURCE GROUP ID: CT040 — 40°F CT ONLY

HIGH 1-Hour

1982	34.27558	50.	200.	82061805
1983	38.54921	350.	200.	83040212
1984	39.98288	220.	200.	84081704
1985	44.84493	190.	200.	85031006
1986	37.07120	10.	200.	86031412

HSH 1-Hour

1982	29.34603	120.	200.	82011413
1983	31.97799	10.	200.	83042311
1984	34.19050	130.	200.	84022811
1985	40.56778	190.	200.	85012306
1986	25.42013	130.	200.	86030117

HIGH 8-Hour

1982	11.06264	120.	200.	82011416
1983	15.73972	110.	200.	83020316
1984	24.71782	120.	200.	84032916
1985	22.17671	360.	200.	85083116
1986	8.70269	100.	200.	86012716

HSH 8-Hour

1982	5.91079	300.	1500.	82051416
1983	9.81146	110.	200.	83042416
1984	17.93479	130.	200.	84022808
1985	12.45903	30.	162.	85083124
1986	7.07129	130.	200.	86030116

SOURCE GROUP ID: CT059 — 59 °F

HIGH 1-Hour

1982	33.20836	50.	200.	82061805
1983	37.39183	350.	200.	83040212
1984	38.80351	220.	200.	84081704
1985	44.00381	190.	200.	85031006

	1986	35.90173	10.	200.	86031412
HSH 1-Hour					
	1982	28.33064	120.	200.	82011413
	1983	31.18593	10.	200.	83042311
	1984	33.05038	130.	200.	84022811
	1985	39.87309	190.	200.	85012306
	1986	24.83786	130.	200.	86030117
HIGH 8-Hour					
	1982	10.69695	120.	200.	82011416
	1983	16.61674	290.	193.	83022716
	1984	23.96863	120.	200.	84032916
	1985	21.47450	360.	200.	85083116
	1986	8.47999	100.	200.	86012716
SH 8-Hour					
	1982	5.91482	360.	1000.	82082716
	1983	10.37966	110.	200.	83042416
	1984	17.40735	130.	200.	84022808
	1985	12.08110	30.	162.	85083124
	1986	6.90051	130.	200.	86030116
OURCE GROUP ID:	CT100				
IGH 1-Hour					
	1982	32.51016	130.	200.	82011414
	1983	33.69687	350.	200.	83040212
	1984	38.75000	220.	200.	84081704
	1985	41.07350	190.	200.	85031006
	1986	33.19429	10.	142.	86031412
HSH 1-Hour					
	1982	27.87585	120.	200.	82011413
	1983	28.35765	10.	200.	83042311
	1984	31.99312	130.	200.	84022811
	1985	37.48651	190.	200.	85012306
	1986	22.77267	130.	200.	86030117
HIGH 8-Hour					
	1982	14.64153	240.	183.	82042316
	1983	15.64402	290.	193.	83022716
	1984	21.85078	120.	200.	84032916
	1985	19.76684	360.	140.	85083116
	1986	10.10853	160.	200.	86010516
HSH 8-Hour					
	1982	8.77448	230.	200.	82110716
	1983	11.14336	100.	200.	83042408
	1984	15.83412	130.	200.	84022808
	1985	12.99793	120.	200.	85110516
	1986	7.81427	230.	200.	86101824
SOURCE GROUP ID:	AUXBLR				
HIGH 1-Hour					
	1982	28.92957	290.	200.	82051021
	1983	37.10068	290.	200.	83051424
	1984	30.42903	300.	210.	84052203
	1985	30.64110	300.	210.	85022212
	1986	32.78995	300.	210.	86052520
HSH 1-Hour					
	1982	28.92957	290.	200.	82120322
	1983	36.25010	290.	200.	83070622
	1984	30.39415	300.	210.	84042705
	1985	30.27352	300.	210.	85022324
	1986	31.56118	300.	210.	86031823
HIGH 8-Hour					
	1982	15.17585	300.	210.	82122416
	1983	12.45329	290.	200.	83022716

100°

AUX. BLR.

1984	15.22147	300.	210.	84022624
1985	11.65628	290.	200.	85112024
1986	15.55304	300.	210.	86031308

SH 8-Hour

1982	12.55088	290.	200.	82122424
1983	10.85351	290.	200.	83012024
1984	15.10129	300.	210.	84030508
1985	10.37806	300.	210.	85021116
1986	15.31325	300.	210.	86031824

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNPM.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNPM.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNPM.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNPM.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNPM.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / PM
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.08433	250.	1000.	82------
	1983	0.06420	250.	1000.	83------
	1984	0.07792	240.	1500.	84------
	1985	0.07147	70.	1000.	85------
	1986	0.08275	90.	1000.	86------
HIGH 24-Hour					
	1982	0.94134	120.	200.	82011424
	1983	1.60243	290.	193.	83022724
	1984	2.61026	130.	200.	84022824
	1985	2.43435	360.	200.	85083124
	1986	0.83515	300.	210.	86031324
HSH 24-Hour					
	1982	0.77915	290.	200.	82120124
	1983	1.26437	110.	200.	83020324
	1984	1.29741	120.	200.	84022824
	1985	1.37547	120.	200.	85010424
	1986	0.81211	300.	210.	86031824

40 °F ALL SOURCES

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL059					
Annual					
	1982	0.08703	250.	1000.	82------
	1983	0.06593	250.	1000.	83------
	1984	0.08034	240.	1500.	84------
	1985	0.07390	70.	1000.	85------
	1986	0.08563	90.	1000.	86------
HIGH 24-Hour					
	1982	1.08901	120.	200.	82011424
	1983	1.80039	290.	193.	83022724
	1984	2.66631	130.	200.	84022824
	1985	2.49389	360.	200.	85083124
	1986	0.91563	130.	200.	86030124
HSH 24-Hour					
	1982	0.77915	290.	200.	82120124
	1983	1.38276	110.	200.	83020324
	1984	1.32578	120.	200.	84022824
	1985	2.03876	120.	200.	85010424
	1986	0.81211	300.	210.	86031824

59 °F

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.10188	250.	1000.	82------
	1983	0.07566	250.	1000.	83------
	1984	0.09238	240.	1500.	84------
	1985	0.08676	80.	1000.	85------
	1986	0.10056	90.	1000.	86------
HIGH 24-Hour					

100 °F

1982	1.60853	290.	193.	82120324
1983	2.36194	290.	193.	83022724
1984	3.47289	130.	200.	84022824
1985	2.93480	120.	200.	85010424
1986	1.21025	230.	200.	86010824

HSH 24-Hour

1982	1.42234	240.	183.	82032824
1983	1.84261	100.	200.	83042424
1984	1.70580	120.	106.	84022824
1985	2.59220	120.	200.	85021224
1986	0.84818	300.	210.	86031824

SOURCE GROUP ID: CT040

40°F CT ONLY

Annual

1982	0.04997	240.	2500.	82------
1983	0.03563	240.	2500.	83------
1984	0.04649	240.	2000.	84------
1985	0.04709	70.	1000.	85------
1986	0.05609	90.	1500.	86------

HIGH 24-Hour

1982	0.86237	120.	200.	82011424
1983	1.25377	110.	200.	83042424
1984	2.48459	130.	200.	84022824
1985	2.42558	360.	200.	85083124
1986	0.64199	130.	200.	86030124

HSH 24-Hour

1982	0.51878	240.	1500.	82082924
1983	1.16076	110.	200.	83020324
1984	1.24701	120.	200.	84022824
1985	1.22402	120.	200.	85010424
1986	0.59276	130.	200.	86012724

SOURCE GROUP ID: CT059

54°F

Annual

1982	0.05208	240.	2000.	82------
1983	0.03743	240.	2000.	83------
1984	0.04887	240.	2000.	84------
1985	0.04952	70.	1000.	85------
1986	0.05808	90.	1500.	86------

HIGH 24-Hour

1982	1.03009	240.	183.	82042324
1983	1.33645	100.	200.	83042424
1984	2.54064	130.	200.	84022824
1985	2.48512	360.	200.	85083124
1986	0.89414	130.	200.	86030124

HSH 24-Hour

1982	0.64246	240.	183.	82032824
1983	1.27915	110.	200.	83020324
1984	1.30548	120.	106.	84022824
1985	1.88731	120.	200.	85010424
1986	0.61114	130.	200.	86012724

SOURCE GROUP ID: CT100

100°F

Annual

1982	0.06448	240.	2000.	82------
1983	0.04574	240.	2000.	83------
1984	0.05955	240.	2000.	84------
1985	0.06206	80.	1000.	85------
1986	0.07194	90.	1000.	86------

HIGH 24-Hour

1982	1.58041	240.	183.	82042324
1983	2.02259	100.	200.	83031824
1984	3.34721	130.	200.	84022824

	1985	2.86830	360.	200.	85083124
	1986	1.21025	230.	200.	86010824
H 24-Hour					
	1982	1.42234	240.	183.	82032824
	1983	1.69799	100.	200.	83042424
	1984	1.69943	120.	106.	84022824
	1985	2.45154	120.	200.	85021224
	1986	0.72708	130.	200.	86012724
SOURCE GROUP ID:	AUXBLR				
nual					
	1982	0.05687	290.	200.	82------
	1983	0.04732	290.	200.	83------
	1984	0.04514	250.	800.	84------
	1985	0.04435	70.	400.	85------
	1986	0.05285	80.	400.	86------
HIGH 24-Hour					
	1982	0.84948	300.	210.	82122424
	1983	0.93817	300.	210.	83030524
	1984	0.79311	300.	210.	84022624
	1985	0.89812	300.	210.	85083024
	1986	0.83515	300.	210.	86031324
HSH 24-Hour					
	1982	0.77915	290.	200.	82120124
	1983	0.64075	300.	210.	83020124
	1984	0.73540	300.	210.	84030524
	1985	0.61206	300.	210.	85112124
	1986	0.81211	300.	210.	86031824

AUX. BLR.

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
ISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNNOX.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNNOX.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNNOX.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNNOX.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNNOX.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / NO2
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)	
SOURCE GROUP ID: ALL040						40°F ALL SOURCES
Annual						
	1982	0.87698	250.	1000.	82------	
	1983	0.66564	250.	1000.	83------	
	1984	0.77187	250.	1000.	84------	
	1985	0.69285	250.	1000.	85------	
	1986	0.77103	90.	800.	86------	
SOURCE GROUP ID: ALL059						59°F
Annual						
	1982	0.88528	250.	1000.	82------	
	1983	0.66949	250.	1000.	83------	
	1984	0.77601	250.	1000.	84------	
	1985	0.69746	250.	1000.	85------	
	1986	0.77741	90.	800.	86------	
SOURCE GROUP ID: ALL100						100°F
Annual						
	1982	0.90281	250.	1000.	82------	
	1983	0.69552	290.	200.	83------	
	1984	0.78257	250.	1000.	84------	
	1985	0.70598	250.	1000.	85------	
	1986	0.78222	90.	800.	86------	
SOURCE GROUP ID: CT040						40°F CT ONLY
Annual						
	1982	0.36247	240.	2500.	82------	
	1983	0.25842	240.	2500.	83------	
	1984	0.33722	240.	2000.	84------	
	1985	0.34160	70.	1000.	85------	
	1986	0.40685	90.	1500.	86------	
SOURCE GROUP ID: CT059						59°F
Annual						
	1982	0.36208	240.	2000.	82------	
	1983	0.26022	240.	2000.	83------	
	1984	0.33974	240.	2000.	84------	
	1985	0.34427	70.	1000.	85------	
	1986	0.40382	90.	1500.	86------	
SOURCE GROUP ID: CT100						100°F
Annual						
	1982	0.34290	240.	2000.	82------	
	1983	0.24322	240.	2000.	83------	
	1984	0.31666	240.	2000.	84------	
	1985	0.32998	80.	1000.	85------	
	1986	0.38254	90.	1000.	86------	
SOURCE GROUP ID: AUXBLR						AUX. BLR
Annual						
	1982	0.71747	290.	200.	82------	
	1983	0.59700	290.	200.	83------	

1984	0.56945	250.	800.	84------
1985	0.55944	70.	400.	85------
1986	0.66668	80.	400.	86------

ll receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNCO.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNCO.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNCO.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNCO.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNCO.086
First title for first output file is   1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / CO
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
HIGH 1-Hour					
	1982	48.81420	290.	200.	82013011
	1983	58.80875	290.	193.	83070622
	1984	40.46173	220.	200.	84081704
	1985	45.92739	190.	200.	85031006
	1986	37.62341	10.	200.	86031412
HSH 1-Hour					
	1982	31.25737	120.	200.	82011413
	1983	55.72579	290.	200.	83022712
	1984	36.12712	130.	200.	84022813
	1985	41.59468	190.	200.	85012306
	1986	31.56118	300.	210.	86031823
HIGH 8-Hour					
	1982	15.17585	300.	210.	82122416
	1983	29.37497	290.	193.	83022716
	1984	27.31887	120.	200.	84032916
	1985	22.68431	360.	200.	85083116
	1986	15.55304	300.	210.	86031308
HSH 8-Hour					
	1982	13.17452	300.	210.	82121516
	1983	13.65508	110.	200.	83042416
	1984	19.99147	130.	200.	84022808
	1985	13.17420	120.	200.	85021216
	1986	15.31325	300.	210.	86031824

40°F ALL SOURCES

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL059					
HIGH 1-Hour					
	1982	48.44765	290.	200.	82013011
	1983	58.32696	290.	193.	83070622
	1984	40.34258	220.	200.	84081704
	1985	45.25053	190.	200.	85031006
	1986	36.64240	10.	200.	86031412
HSH 1-Hour					
	1982	43.65388	290.	193.	82020404
	1983	54.88261	290.	200.	83022712
	1984	35.65252	100.	200.	84041613
	1985	41.04202	190.	200.	85012306
	1986	31.56118	300.	210.	86031823
HIGH 8-Hour					
	1982	15.17585	300.	210.	82122416
	1983	29.06007	290.	193.	83022716
	1984	26.69195	120.	200.	84032916
	1985	22.09525	360.	200.	85083116
	1986	15.55304	300.	210.	86031308
HSH 8-Hour					
	1982	13.09269	300.	210.	82121516

59°F

	1983	14.19674	120.	200.	83032116	
	1984	19.55088	130.	200.	84022808	
	1985	14.91416	120.	200.	85021216	
	1986	15.31325	300.	210.	86031824	
SOURCE GROUP ID: ALL100						100°F
HIGH 1-Hour						
	1982	46.63850	290.	200.	82013011	
	1983	$\boxed{56.04659}$	290.	193.	83070622	
	1984	45.12063	290.	200.	84102020	
	1985	44.55350	290.	200.	85041823	
	1986	34.14188	10.	142.	86031412	
HSH 1-Hour						
	1982	44.73096	290.	200.	82051021	
	1983	54.24386	290.	200.	83051424	
	1984	44.73096	290.	200.	84102024	
	1985	39.61539	290.	200.	85112020	
	1986	31.75400	300.	210.	86031823	
HIGH 8-Hour						
	1982	20.05154	290.	200.	82122424	
	1983	$\boxed{27.97041}$	290.	193.	83022716	
	1984	24.52362	120.	200.	84032916	
	1985	20.33607	360.	200.	85083116	
	1986	15.77972	300.	210.	86031308	
HSH 8-Hour						
	1982	15.83042	290.	200.	82013024	
	1983	13.57748	120.	200.	83020316	
	1984	17.91063	130.	200.	84022808	
	1985	14.39722	120.	200.	85110516	
	1986	15.77691	300.	210.	86031824	
SOURCE GROUP ID: CT040						40°F CT ONLY
HIGH 1-Hour						
	1982	34.79632	50.	200.	82061805	
	1983	39.16595	350.	200.	83040212	
	1984	40.46173	220.	200.	84081704	
	1985	45.92739	190.	200.	85031006	
	1986	37.62341	10.	200.	86031412	
HSH 1-Hour						
	1982	29.71820	120.	200.	82011413	
	1983	32.61107	10.	200.	83042311	
	1984	34.65522	130.	200.	84022811	
	1985	41.59468	190.	200.	85012306	
	1986	25.95756	130.	200.	86030117	
HIGH 8-Hour						
	1982	11.21531	120.	200.	82011416	
	1983	17.36382	290.	193.	83022716	
	1984	25.10810	120.	200.	84032916	
	1985	22.50515	360.	200.	85083116	
	1986	8.86980	100.	200.	86012716	
HSH 8-Hour						
	1982	6.13279	360.	1000.	82082716	
	1983	10.85569	110.	200.	83042416	
	1984	18.22966	130.	200.	84022808	
	1985	12.65551	30.	162.	85083124	
	1986	7.21441	130.	200.	86030116	
SOURCE GROUP ID: CT059						59°F
HIGH 1-Hour						
	1982	33.90173	50.	200.	82061805	
	1983	38.19755	350.	200.	83040212	
	1984	40.34258	220.	200.	84081704	
	1985	45.25053	190.	200.	85031006	

	1986	36.64240	10.	200.	86031412
HSH 1-Hour					
	1982	28.86300	120.	200.	82011413
	1983	31.95679	10.	200.	83042311
	1984	33.69641	130.	200.	84022811
	1985	41.04202	190.	200.	85012306
	1986	25.47978	130.	200.	86030117
HIGH 8-Hour					
	1982	13.38774	160.	200.	82022216
	1983	17.07178	110.	200.	83020316
	1984	24.48118	120.	200.	84032916
	1985	21.91609	360.	200.	85083116
	1986	8.81901	130.	200.	86030116
SH 8-Hour					
	1982	6.15625	360.	1000.	82082716
	1983	11.57532	90.	200.	83042408
	1984	17.78908	130.	200.	84022808
	1985	13.45233	120.	200.	85010416
	1986	7.61747	130.	200.	86012724
OURCE GROUP ID:	CT100				
IGH 1-Hour					
	1982	33.24274	130.	200.	82011414
	1983	34.58192	350.	200.	83040212
	1984	39.59442	220.	200.	84081704
	1985	41.82648	190.	200.	85031006
	1986	34.14188	10.	142.	86031412
SH 1-Hour					
	1982	28.50003	120.	200.	82011413
	1983	28.82767	10.	200.	83042311
	1984	32.74077	130.	200.	84022811
	1985	38.19214	190.	200.	85012306
	1986	23.16296	130.	200.	86030117
HIGH 8-Hour					
	1982	14.90806	240.	183.	82042316
	1983	15.95926	290.	193.	83022716
	1984	22.31285	120.	200.	84032916
	1985	20.23825	360.	140.	85083116
	1986	10.30637	160.	200.	86010516
HSH 8-Hour					
	1982	9.70267	250.	193.	82043024
	1983	11.34429	100.	200.	83042408
	1984	16.14883	130.	200.	84022808
	1985	13.24109	120.	200.	85110516
	1986	7.97033	230.	200.	86101824
SOURCE GROUP ID:	AUXBLR				
HIGH 1-Hour					
	1982	28.92957	290.	200.	82051021
	1983	37.10068	290.	200.	83051424
	1984	30.42903	300.	210.	84052203
	1985	30.64110	300.	210.	85022212
	1986	32.78995	300.	210.	86052520
HSH 1-Hour					
	1982	28.92957	290.	200.	82120322
	1983	36.25010	290.	200.	83070622
	1984	30.39415	300.	210.	84042705
	1985	30.27352	300.	210.	85022324
	1986	31.56118	300.	210.	86031823
HIGH 8-Hour					
	1982	15.17585	300.	210.	82122416
	1983	12.45329	290.	200.	83022716

100°F

AUX. BLR

	1984	15.22147	300.	210.	84022624
	1985	11.65628	290.	200.	85112024
	1986	15.55304	300.	210.	86031308
HSH 8-Hour					
	1982	12.55088	290.	200.	82122424
	1983	10.85351	290.	200.	83012024
	1984	15.10129	300.	210.	84030508
	1985	10.37806	300.	210.	85021116
	1986	15.31325	300.	210.	86031824

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCSSREF.082

rst title for first output file is 1982 ARK ENERGY-ORANGECO / SIMPLE CYCLE / GENERIC EMISSIONS 10 G/S

cond title for first output file is REFINEMENT / 100 DEG / 60' CT STACK

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
URCE GROUP ID: GSS100					
HIGH 1-Hour					
	1982	265.70499	152.	104.	82011414
H 1-Hour					
	1982	154.80836	144.	113.	82011414

All receptor computations reported with respect to a user-specified origin

RID	0.00	0.00
ISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNPMRF.084
First title for first output file is 1984 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / PM / REFINEMENT
Second title for first output file is 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL100					
HIGH 24-Hour					
	1984	3.47289	130.	200.	84022824
HSH 24-Hour					
	1984	2.60184	124.	200.	84022824
SOURCE GROUP ID: CT100					
HIGH 24-Hour					
	1984	3.34721	130.	200.	84022824
HSH 24-Hour					
	1984	2.52872	124.	200.	84022824
SOURCE GROUP ID: AUXBLR					
HIGH 24-Hour					
	1984	0.51024	134.	400.	84022824
HSH 24-Hour					
	1984	0.37851	124.	400.	84040524

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNCORF.083
First title for first output file is   1983 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / CO / REFINEMENT
Second title for first output file is 40 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
HIGH 8-Hour					
	1983	34.83726	286.	200.	83022716
HSH 8-Hour					
	1983	14.06484	286.	200.	83022016
SOURCE GROUP ID: CT040					
HIGH 8-Hour					
	1983	18.15022	288.	191.	83022716
HSH 8-Hour					
	1983	3.77474	296.	202.	83070624
SOURCE GROUP ID: AUXBLR					
HIGH 8-Hour					
	1983	17.60450	286.	200.	83022716
HSH 8-Hour					
	1983	14.06484	286.	200.	83022016

All receptor computations reported with respect to a user-specified origin

GRID 0.00 0.00
DISCRETE 0.00 0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNFORM.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNFORM.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNFORM.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNFORM.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNFORM.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / FORMALDEHYDE
Second title for first output file is 40 and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.00065	250.	1000.	82------
	1983	0.00049	250.	1000.	83------
	1984	0.00058	240.	1500.	84------
	1985	0.00052	70.	800.	85------
	1986	0.00060	90.	1000.	86------
HIGH 8-Hour					
	1982	0.01468	120.	200.	82011416
	1983	0.03091	290.	193.	83022716
	1984	0.03147	120.	200.	84032916
	1985	0.02663	360.	200.	85083116
	1986	0.01358	300.	210.	86031308
HSH 8-Hour					
	1982	0.01257	300.	210.	82121516
	1983	0.01522	110.	200.	83042416
	1984	0.02298	130.	200.	84022808
	1985	0.01514	120.	200.	85021216
	1986	0.01337	300.	210.	86031824
HIGH 24-Hour					
	1982	0.00719	300.	210.	82122424
	1983	0.01176	290.	200.	83022724
	1984	0.01763	130.	200.	84022824
	1985	0.01624	360.	200.	85083124
	1986	0.00707	300.	210.	86031324
HSH 24-Hour					
	1982	0.00659	290.	200.	82120124
	1983	0.00862	110.	200.	83020324
	1984	0.00874	120.	200.	84022824
	1985	0.00944	120.	200.	85010424
	1986	0.00687	300.	210.	86031824
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.00067	250.	1000.	82------
	1983	0.00050	250.	1000.	83------
	1984	0.00058	250.	1000.	84------
	1985	0.00053	250.	1000.	85------
	1986	0.00060	90.	800.	86------
HIGH 8-Hour					
	1982	0.01929	290.	200.	82122424
	1983	0.02822	290.	193.	83022716
	1984	0.02672	120.	200.	84032916
	1985	0.02255	360.	200.	85083116
	1986	0.01388	300.	210.	86031824
HSH 8-Hour					
	1982	0.01500	290.	200.	82013024
	1983	0.01450	120.	200.	83020316
	1984	0.01948	130.	200.	84022808
	1985	0.01572	120.	200.	85110516
	1986	0.01383	300.	210.	86031308
HIGH 24-Hour					
	1982	0.01055	290.	193.	82120324

40°F ALL SOURCES

100°F ALL SOURCES

	1983	0.01340	290.	193.	83022724
	1984	$\boxed{0.01700}$	130.	200.	84022824
	1985	0.01454	120.	200.	85010424
	1986	0.00747	300.	210.	86031324
HSH 24-Hour					
	1982	0.00767	290.	200.	82122424
	1983	0.01099	290.	200.	83012024
	1984	0.00815	120.	106.	84022824
	1985	0.01286	120.	200.	85021224
	1986	0.00704	300.	210.	86031824
SOURCE GROUP ID:	CT040				
Annual					
	1982	0.00033	240.	2500.	82------
	1983	0.00024	240.	2500.	83------
	1984	0.00031	240.	2000.	84------
	1985	0.00031	70.	1000.	85------
	1986	0.00037	90.	1500.	86------
HIGH 8-Hour					
	1982	0.01319	120.	200.	82011416
	1983	0.02043	290.	193.	83022716
	1984	0.02954	120.	200.	84032916
	1985	0.02648	360.	200.	85083116
	1986	0.01044	100.	200.	86012716
HSH 8-Hour					
	1982	0.00722	360.	1000.	82082716
	1983	0.01277	110.	200.	83042416
	1984	0.02145	130.	200.	84022808
	1985	0.01489	30.	162.	85083124
	1986	0.00849	130.	200.	86030116
HIGH 24-Hour					
	1982	0.00575	120.	200.	82011424
	1983	0.00836	110.	200.	83042424
	1984	0.01656	130.	200.	84022824
	1985	0.01617	360.	200.	85083124
	1986	0.00428	130.	200.	86030124
HSH 24-Hour					
	1982	0.00346	240.	1500.	82082924
	1983	0.00774	110.	200.	83020324
	1984	0.00831	120.	200.	84022824
	1985	0.00816	120.	200.	85010424
	1986	0.00395	130.	200.	86012724
SOURCE GROUP ID:	CT100				
Annual					
	1982	0.00031	240.	2000.	82------
	1983	0.00022	240.	2000.	83------
	1984	0.00028	240.	2000.	84------
	1985	0.00030	80.	1000.	85------
	1986	0.00034	90.	1000.	86------
HIGH 8-Hour					
	1982	0.01656	240.	183.	82042316
	1983	0.01773	290.	193.	83022716
	1984	0.02479	120.	200.	84032916
	1985	0.02249	360.	140.	85083116
	1986	0.01145	160.	200.	86010516
HSH 8-Hour					
	1982	0.01078	250.	193.	82043024
	1983	0.01260	100.	200.	83042408
	1984	0.01794	130.	200.	84022808
	1985	0.01471	120.	200.	85110516
	1986	0.00886	230.	200.	86101824
HIGH 24-Hour					
	1982	0.00753	240.	183.	82042324
	1983	0.00963	100.	200.	83031824
	1984	0.01594	130.	200.	84022824
	1985	0.01366	360.	200.	85083124
	1986	0.00576	230.	200.	86010824

40°F CT ONLY

100°F

HSH 24-Hour					
	1982	0.00677	240.	183.	82032824
	1983	0.00809	100.	200.	83042424
	1984	0.00809	120.	106.	84022824
	1985	0.01167	120.	200.	85021224
	1986	0.00346	130.	200.	86012724

SOURCE GROUP ID: AUXBLR

AUX. BLR.

Annual					
	1982	0.00048	290.	200.	82------
	1983	0.00040	290.	200.	83------
	1984	0.00038	250.	800.	84------
	1985	0.00038	70.	400.	85------
	1986	0.00045	80.	400.	86------
HIGH 8-Hour					
	1982	0.01325	300.	210.	82122416
	1983	0.01087	290.	200.	83022716
	1984	0.01329	300.	210.	84022624
	1985	0.01018	290.	200.	85112024
	1986	0.01358	300.	210.	86031308
HSH 8-Hour					
	1982	0.01096	290.	200.	82122424
	1983	0.00948	290.	200.	83012024
	1984	0.01318	300.	210.	84030508
	1985	0.00906	300.	210.	85021116
	1986	0.01337	300.	210.	86031824
HIGH 24-Hour					
	1982	0.00719	300.	210.	82122424
	1983	0.00794	300.	210.	83030524
	1984	0.00671	300.	210.	84022624
	1985	0.00760	300.	210.	85083024
	1986	0.00707	300.	210.	86031324
HSH 24-Hour					
	1982	0.00659	290.	200.	82120124
	1983	0.00542	300.	210.	83020124
	1984	0.00622	300.	210.	84030524
	1985	0.00518	300.	210.	85112124
	1986	0.00687	300.	210.	86031824

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNPOM.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNPOM.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNPOM.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNPOM.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNPOM.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / POM'S
Second title for first output file is 40 and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.00001	250.	1000.	82------
	1983	0.00001	250.	1000.	83------
	1984	0.00001	240.	1500.	84------
	1985	0.00001	70.	800.	85------
	1986	0.00001	90.	1000.	86------
HIGH 8-Hour					
	1982	0.00019	120.	200.	82011416
	1983	0.00039	290.	193.	83022716
	1984	0.00040	120.	200.	84032916
	1985	0.00034	360.	200.	85083116
	1986	0.00017	300.	210.	86031308
HSH 8-Hour					
	1982	0.00016	300.	210.	82121516
	1983	0.00019	110.	200.	83042416
	1984	0.00029	130.	200.	84022808
	1985	0.00019	120.	200.	85021216
	1986	0.00017	300.	210.	86031824
HIGH 24-Hour					
	1982	0.00009	300.	210.	82122424
	1983	0.00015	290.	200.	83022724
	1984	0.00022	130.	200.	84022824
	1985	0.00021	360.	200.	85083124
	1986	0.00009	300.	210.	86031324
HSH 24-Hour					
	1982	0.00008	290.	200.	82120124
	1983	0.00011	110.	200.	83020324
	1984	0.00011	120.	200.	84022824
	1985	0.00012	120.	200.	85010424
	1986	0.00009	300.	210.	86031824
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.00001	250.	1000.	82------
	1983	0.00001	250.	1000.	83------
	1984	0.00001	250.	1000.	84------
	1985	0.00001	250.	1000.	85------
	1986	0.00001	90.	800.	86------
HIGH 8-Hour					
	1982	0.00025	290.	200.	82122424
	1983	0.00036	290.	193.	83022716
	1984	0.00034	120.	200.	84032916
	1985	0.00029	360.	200.	85083116
	1986	0.00018	300.	210.	86031824
HSH 8-Hour					
	1982	0.00019	290.	200.	82013024
	1983	0.00018	120.	200.	83020316
	1984	0.00025	130.	200.	84022808
	1985	0.00020	120.	200.	85110516
	1986	0.00018	300.	210.	86031308
HIGH 24-Hour					
	1982	0.00013	290.	193.	82120324

40°F ALL SOURCES

100°F ALL SOURCES

	1983	0.00017	290.	193.	83022724
	1984	$\boxed{0.00022}$	130.	200.	84022824
	1985	0.00018	120.	200.	85010424
	1986	0.00010	300.	210.	86031324
HSH 24-Hour					
	1982	0.00010	290.	200.	82122424
	1983	0.00014	290.	200.	83012024
	1984	0.00010	120.	106.	84022824
	1985	0.00016	120.	200.	85021224
	1986	0.00009	300.	210.	86031824
SOURCE GROUP ID:	CT040				
Annual					
	1982	0.00000	240.	2500.	82------
	1983	0.00000	240.	2500.	83------
	1984	0.00000	240.	2000.	84------
	1985	0.00000	70.	1000.	85------
	1986	0.00000	90.	1500.	86------
HIGH 8-Hour					
	1982	0.00017	120.	200.	82011416
	1983	0.00026	290.	193.	83022716
	1984	0.00037	120.	200.	84032916
	1985	0.00033	360.	200.	85083116
	1986	0.00013	100.	200.	86012716
HSH 8-Hour					
	1982	0.00009	360.	1000.	82082716
	1983	0.00016	110.	200.	83042416
	1984	0.00027	130.	200.	84022808
	1985	0.00019	30.	162.	85083124
	1986	0.00011	130.	200.	86030116
HIGH 24-Hour					
	1982	0.00007	120.	200.	82011424
	1983	0.00011	110.	200.	83042424
	1984	0.00021	130.	200.	84022824
	1985	0.00020	360.	200.	85083124
	1986	0.00005	130.	200.	86030124
HSH 24-Hour					
	1982	0.00004	240.	1500.	82082924
	1983	0.00010	110.	200.	83020324
	1984	0.00010	120.	200.	84022824
	1985	0.00010	120.	200.	85010424
	1986	0.00005	130.	200.	86012724
SOURCE GROUP ID:	CT100				
Annual					
	1982	0.00000	240.	2000.	82------
	1983	0.00000	240.	2000.	83------
	1984	0.00000	240.	2000.	84------
	1985	0.00000	80.	1000.	85------
	1986	0.00000	90.	1000.	86------
HIGH 8-Hour					
	1982	0.00021	240.	183.	82042316
	1983	0.00022	290.	193.	83022716
	1984	0.00031	120.	200.	84032916
	1985	0.00028	360.	140.	85083116
	1986	0.00015	160.	200.	86010516
HSH 8-Hour					
	1982	0.00014	250.	193.	82043024
	1983	0.00016	100.	200.	83042408
	1984	0.00023	130.	200.	84022808
	1985	0.00019	120.	200.	85110516
	1986	0.00011	230.	200.	86101824
HIGH 24-Hour					
	1982	0.00010	240.	183.	82042324
	1983	0.00012	100.	200.	83031824
	1984	0.00020	130.	200.	84022824
	1985	0.00017	360.	200.	85083124
	1986	0.00007	230.	200.	86010824

40°F CT ONLY

100°F

HSH 24-Hour

	1982	0.00009	240.	183.	82032824
	1983	0.00010	100.	200.	83042424
	1984	0.00010	120.	106.	84022824
	1985	0.00015	120.	200.	85021224
	1986	0.00004	130.	200.	86012724

SOURCE GROUP ID: AUXBLR

AUX. BLR.

Annual

	1982	0.00001	290.	200.	82------
	1983	0.00001	290.	200.	83------
	1984	0.00000	250.	800.	84------
	1985	0.00000	70.	400.	85------
	1986	0.00001	80.	400.	86------
HIGH 8-Hour					
	1982	0.00017	300.	210.	82122416
	1983	0.00014	290.	200.	83022716
	1984	0.00017	300.	210.	84022624
	1985	0.00013	290.	200.	85112024
	1986	0.00017	300.	210.	86031308
HSH 8-Hour					
	1982	0.00014	290.	200.	82122424
	1983	0.00012	290.	200.	83012024
	1984	0.00017	300.	210.	84030508
	1985	0.00012	300.	210.	85021116
	1986	0.00017	300.	210.	86031824
HIGH 24-Hour					
	1982	0.00009	300.	210.	82122424
	1983	0.00010	300.	210.	83030524
	1984	0.00009	300.	210.	84022624
	1985	0.00010	300.	210.	85083024
	1986	0.00009	300.	210.	86031324
HSH 24-Hour					
	1982	0.00008	290.	200.	82120124
	1983	0.00007	300.	210.	83020124
	1984	0.00008	300.	210.	84030524
	1985	0.00007	300.	210.	85112124
	1986	0.00009	300.	210.	86031824

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNMIST.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNMIST.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNMIST.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNMIST.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNMIST.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / COMBINED CYCLE-DLNOX / SULF ACID MIST
Second title for first output file is 40 and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.00166	250.	1000.	82------
	1983	0.00126	250.	1000.	83------
	1984	0.00146	250.	1000.	84------
	1985	0.00132	250.	1000.	85------
	1986	0.00150	90.	800.	86------
HIGH 8-Hour					
	1982	0.03532	120.	200.	82011416
	1983	0.07628	290.	193.	83022716
	1984	0.07542	120.	200.	84032916
	1985	0.06345	360.	200.	85083116
	1986	0.03580	300.	210.	86031308
HSH 8-Hour					
	1982	0.03208	300.	210.	82121516
	1983	0.03685	110.	200.	83042416
	1984	0.05512	130.	200.	84022808
	1985	0.03630	120.	200.	85021216
	1986	0.03524	300.	210.	86031824
HIGH 24-Hour					
	1982	0.01895	300.	210.	82122424
	1983	0.02932	290.	200.	83022724
	1984	0.04224	130.	200.	84022824
	1985	0.03870	360.	200.	85083124
	1986	0.01863	300.	210.	86031324
HSH 24-Hour					
	1982	0.01738	290.	200.	82120124
	1983	0.02074	110.	200.	83020324
	1984	0.02092	120.	200.	84022824
	1985	0.02281	120.	200.	85010424
	1986	0.01812	300.	210.	86031824
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.00174	250.	1000.	82------
	1983	0.00129	250.	1000.	83------
	1984	0.00150	250.	1000.	84------
	1985	0.00136	250.	1000.	85------
	1986	0.00155	90.	800.	86------
HIGH 8-Hour					
	1982	0.05000	290.	200.	82122424
	1983	0.07257	290.	193.	83022716
	1984	0.06789	120.	200.	84032916
	1985	0.05715	360.	200.	85083116
	1986	0.03655	300.	210.	86031824
HSH 8-Hour					
	1982	0.03898	290.	200.	82013024
	1983	0.03695	120.	200.	83020316
	1984	0.04951	130.	200.	84022808
	1985	0.03993	120.	200.	85110516
	1986	0.03643	300.	210.	86031308
HIGH 24-Hour					
	1982	0.02741	290.	193.	82120324

40°F ALL SOURCES

100°F ALL SOURCES

	1983	0.03445	290.	193.	83022724	
	1984	$\boxed{0.04318}$	130.	200.	84022824	
	1985	0.03696	120.	200.	85010424	
	1986	0.01966	300.	210.	86031324	
HSH 24-Hour						
	1982	0.01993	290.	200.	82122424	
	1983	0.02857	290.	200.	83012024	
	1984	0.02064	120.	106.	84022824	
	1985	0.03271	120.	200.	85021224	
	1986	0.01855	300.	210.	86031824	
SOURCE GROUP ID:	CT040					40°F CT ONLY
Annual						
	1982	0.00079	240.	2500.	82------	
	1983	0.00057	240.	2500.	83------	
	1984	0.00074	240.	2000.	84------	
	1985	0.00075	70.	1000.	85------	
	1986	0.00089	90.	1500.	86------	
HIGH 8-Hour						
	1982	0.03142	120.	200.	82011416	
	1983	0.04864	290.	193.	83022716	
	1984	0.07033	120.	200.	84032916	
	1985	0.06304	360.	200.	85083116	
	1986	0.02485	100.	200.	86012716	
HSH 8-Hour						
	1982	0.01718	360.	1000.	82082716	
	1983	0.03041	110.	200.	83042416	
	1984	0.05106	130.	200.	84022808	
	1985	0.03545	30.	162.	85083124	
	1986	0.02021	130.	200.	86030116	
HIGH 24-Hour						
	1982	0.01369	120.	200.	82011424	
	1983	0.01990	110.	200.	83042424	
	1984	0.03944	130.	200.	84022824	
	1985	0.03850	360.	200.	85083124	
	1986	0.01019	130.	200.	86030124	
HSH 24-Hour						
	1982	0.00823	240.	1500.	82082924	
	1983	0.01842	110.	200.	83020324	
	1984	0.01979	120.	200.	84022824	
	1985	0.01943	120.	200.	85010424	
	1986	0.00941	130.	200.	86012724	
SOURCE GROUP ID:	CT100					100°F CT ONLY
Annual						
	1982	0.00078	240.	2000.	82------	
	1983	0.00055	240.	2000.	83------	
	1984	0.00072	240.	2000.	84------	
	1985	0.00075	80.	1000.	85------	
	1986	0.00087	90.	1000.	86------	
HIGH 8-Hour						
	1982	0.04196	240.	183.	82042316	
	1983	0.04492	290.	193.	83022716	
	1984	0.06281	120.	200.	84032916	
	1985	0.05697	360.	140.	85083116	
	1986	0.02901	160.	200.	86010516	
HSH 8-Hour						
	1982	0.02731	250.	193.	82043024	
	1983	0.03193	100.	200.	83042408	
	1984	0.04546	130.	200.	84022808	
	1985	0.03727	120.	200.	85110516	
	1986	0.02244	230.	200.	86101824	
HIGH 24-Hour						
	1982	0.01907	240.	183.	82042324	
	1983	0.02440	100.	200.	83031824	
	1984	0.04038	130.	200.	84022824	
	1985	0.03460	360.	200.	85083124	
	1986	0.01460	230.	200.	86010824	

HSH 24-Hour

	1982	0.01716	240.	183.	82032824
	1983	0.02048	100.	200.	83042424
	1984	0.02050	120.	106.	84022824
	1985	0.02957	120.	200.	85021224
	1986	0.00877	130.	200.	86012724

SOURCE GROUP ID: AUXBLR

AUX. BLR.

Annual

	1982	0.00127	290.	200.	82------
	1983	0.00106	290.	200.	83------
	1984	0.00101	250.	800.	84------
	1985	0.00099	70.	400.	85------
	1986	0.00118	80.	400.	86------
HIGH 8-Hour					
	1982	0.03493	300.	210.	82122416
	1983	0.02866	290.	200.	83022716
	1984	0.03503	300.	210.	84022624
	1985	0.02683	290.	200.	85112024
	1986	0.03580	300.	210.	86031308
HSH 8-Hour					
	1982	0.02889	290.	200.	82122424
	1983	0.02498	290.	200.	83012024
	1984	0.03476	300.	210.	84030508
	1985	0.02389	300.	210.	85021116
	1986	0.03524	300.	210.	86031824
HIGH 24-Hour					
	1982	0.01895	300.	210.	82122424
	1983	0.02093	300.	210.	83030524
	1984	0.01769	300.	210.	84022624
	1985	0.02003	300.	210.	85083024
	1986	0.01863	300.	210.	86031324
HSH 24-Hour					
	1982	0.01738	290.	200.	82120124
	1983	0.01429	300.	210.	83020124
	1984	0.01641	300.	210.	84030524
	1985	0.01365	300.	210.	85112124
	1986	0.01812	300.	210.	86031824

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

Summary of PSD Class 1 Air Dispersion Impacts for the Orange Cogeneration Facility, Bartow, Florida; Simple Cycle Operation
(Three Ambient Temperatures)

OCSSC1GN
06/25/93

Ambient Temperature (°F)	Number of Units	Pollutant	Emission Rate Basis		Per Unit Emission Rate		Total Facility Emission Rate			Modeled Emission Rate (g/s)	Averaging Period	Generic Modeled Conc (µg/m³)	Actual Conc (µg/m³)	Class 1 Sig. Values (µg/m³)
			Rate	Units	Rate	Units	Rate	Units	(g/s)					
20	1	Particulate	5	lb/hr	5.0	lb/hr	5.0	lb/hr	0.63	10.00	24-hour	0.16	0.010	0.33
											Annual	0.0089	0.00056	0.1
		Nitrogen Dioxide	25	ppmvd	156.5	TPY	156.5	TPY	4.50	10.00	Annual	0.0089	0.0031	0.025
40	1	Particulate	5	lb/hr	5.0	lb/hr	5.0	lb/hr	0.63	10.00	24-hour	0.16	0.010	0.33
											Annual	0.0086	0.00054	0.1
		Nitrogen Dioxide	25	ppmvd	165.7	TPY	165.73	TPY	4.77	10.00	Annual	0.0086	0.0041	0.025
100	1	Particulate	5	lb/hr	5.0	lb/hr	5.0	lb/hr	0.63	10.00	24-hour	0.18	0.011	0.33
											Annual	0.0095	0.00060	0.1
		Nitrogen Dioxide	25	ppmvd	119.5	TPY	119.5	TPY	3.44	10.00	Annual	0.0095	0.0033	0.025

Note: All stack parameters and emission rates apply to the CT operating in simple cycle mode with water injection using natural gas.

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCSSC1.082
ISCST2 OUTPUT FILE NUMBER 2 :OCSSC1.083
ISCST2 OUTPUT FILE NUMBER 3 :OCSSC1.084
ISCST2 OUTPUT FILE NUMBER 4 :OCSSC1.085
ISCST2 OUTPUT FILE NUMBER 5 :OCSSC1.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / CLASS 1 / SIMPLE CYCLE / GENERIC EMISSION
Second title for first output file is 20,40, and 100 DEG / 60' CT STACK

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: GSS020					20°F ALL
Annual					
	1982	0.00891	340300.	3165700.	82------
	1983	0.00620	343700.	3178300.	83------
	1984	0.00572	340300.	3165700.	84------
	1985	0.00578	340300.	3165700.	85------
	1986	0.00791	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.16398	340300.	3169800.	82122124
	1983	0.13602	342400.	3180600.	83090424
	1984	0.09497	343000.	3176200.	84041924
	1985	0.13397	340300.	3165700.	85082224
	1986	0.12120	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.12950	340300.	3165700.	82122124
	1983	0.11327	341100.	3183400.	83120224
	1984	0.08020	340300.	3165700.	84082124
	1985	0.10110	340300.	3165700.	85082124
	1986	0.10707	342000.	3174000.	86053024
SOURCE GROUP ID: GSS040					40°F ALL
Annual					
	1982	0.00862	340300.	3165700.	82------
	1983	0.00599	343700.	3178300.	83------
	1984	0.00558	340300.	3165700.	84------
	1985	0.00560	340300.	3165700.	85------
	1986	0.00764	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.15798	340300.	3169800.	82122124
	1983	0.13152	342400.	3180600.	83090424
	1984	0.09129	343000.	3176200.	84041924
	1985	0.12819	340300.	3165700.	85082224
	1986	0.11777	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.12482	340300.	3165700.	82122124
	1983	0.10890	341100.	3183400.	83120224
	1984	0.07695	340300.	3165700.	84082124
	1985	0.09069	340300.	3165700.	85082124
	1986	0.10300	343000.	3176200.	86120124
SOURCE GROUP ID: GSS100					100°F ALL
Annual					
	1982	0.00946	340300.	3165700.	82------
	1983	0.00648	343700.	3178300.	83------
	1984	0.00598	340300.	3165700.	84------
	1985	0.00613	340300.	3165700.	85------
	1986	0.00846	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.17789	340300.	3169800.	82122124
	1983	0.14834	342400.	3180600.	83090424
	1984	0.10145	343000.	3176200.	84041924
	1985	0.14303	340300.	3165700.	85082224
	1986	0.12635	342000.	3174000.	86080324
HSH 24-Hour					

1982	0.14136	340300.	3165700.	82122124
1983	0.12181	341100.	3183400.	83120224
1984	0.08518	340300.	3165700.	84082124
1985	0.10645	340300.	3165700.	85082124
1986	0.11652	342000.	3174000.	86051924

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCWIC1PM.082
ISCST2 OUTPUT FILE NUMBER 2 :OCWIC1PM.083
ISCST2 OUTPUT FILE NUMBER 3 :OCWIC1PM.084
ISCST2 OUTPUT FILE NUMBER 4 :OCWIC1PM.085
ISCST2 OUTPUT FILE NUMBER 5 :OCWIC1PM.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / CLASS 1 / COMBINED CYCLE-WATER INJ / PM
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.00160	340300.	3165700.	82------
	1983	0.00108	343700.	3178300.	83------
	1984	0.00104	340300.	3165700.	84------
	1985	0.00102	340300.	3165700.	85------
	1986	0.00143	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02810	340300.	3165700.	82081424
	1983	0.02159	343700.	3178300.	83090424
	1984	0.02006	343000.	3176200.	84041924
	1985	0.02666	340300.	3165700.	85082224
	1986	0.02448	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02509	343700.	3178300.	82062524
	1983	0.02052	342400.	3180600.	83120224
	1984	0.01632	343000.	3176200.	84050224
	1985	0.01889	340300.	3165700.	85082124
	1986	0.02195	342000.	3174000.	86053024
SOURCE GROUP ID: ALL059					
Annual					
	1982	0.00162	340300.	3165700.	82------
	1983	0.00110	343700.	3178300.	83------
	1984	0.00106	340300.	3165700.	84------
	1985	0.00103	340300.	3165700.	85------
	1986	0.00146	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02838	340300.	3165700.	82081424
	1983	0.02175	343700.	3178300.	83090424
	1984	0.02024	343000.	3176200.	84041924
	1985	0.02693	340300.	3165700.	85082224
	1986	0.02462	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02536	343700.	3178300.	82062524
	1983	0.02071	342400.	3180600.	83120224
	1984	0.01649	343000.	3176200.	84050224
	1985	0.01904	340300.	3165700.	85082124
	1986	0.02214	342000.	3174000.	86053024
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.00165	340300.	3165700.	82------
	1983	0.00113	343700.	3178300.	83------
	1984	0.00108	340300.	3165700.	84------
	1985	0.00108	340300.	3165700.	85------
	1986	0.00149	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02960	340300.	3165700.	82081424
	1983	0.02239	343700.	3178300.	83090424
	1984	0.02099	343000.	3176200.	84041924
	1985	0.02807	340300.	3165700.	85082224
	1986	0.02521	342000.	3174000.	86080324
HSH 24-Hour					

40°F ALL

59°F ALL

100°F ALL

	1982	0.02649	343700.	3178300.	82062524	
	1983	0.02151	342400.	3180600.	83120224	
	1984	0.01724	343000.	3176200.	84050224	
	1985	0.01972	340300.	3165700.	85082124	
	1986	0.02293	342000.	3174000.	86053024	
SOURCE GROUP ID:	CT040					40°F CT ONLY
Annual						
	1982	$\boxed{0.00139}$	340300.	3165700.	82------	
	1983	0.00094	343700.	3178300.	83------	
	1984	0.00090	340300.	3165700.	84------	
	1985	0.00089	340300.	3165700.	85------	
	1986	0.00123	340300.	3165700.	86------	
HIGH 24-Hour						
	1982	$\boxed{0.02371}$	340300.	3169800.	82122124	
	1983	0.01850	343700.	3178300.	83090424	
	1984	0.01708	343000.	3176200.	84041924	
	1985	0.02248	340300.	3165700.	85082224	
	1986	0.02128	342000.	3174000.	86080324	
HSH 24-Hour						
	1982	0.02110	343700.	3178300.	82062524	
	1983	0.01756	341100.	3183400.	83090424	
	1984	0.01371	343000.	3176200.	84050224	
	1985	0.01614	340300.	3165700.	85082124	
	1986	0.01869	342000.	3174000.	86053024	
SOURCE GROUP ID:	CT059					59 °F
Annual						
	1982	$\boxed{0.00141}$	340300.	3165700.	82------	
	1983	0.00096	343700.	3178300.	83------	
	1984	0.00092	340300.	3165700.	84------	
	1985	0.00089	340300.	3165700.	85------	
	1986	0.00125	340300.	3165700.	86------	
HIGH 24-Hour						
	1982	$\boxed{0.02397}$	340300.	3165700.	82081424	
	1983	0.01865	343700.	3178300.	83090424	
	1984	0.01725	343000.	3176200.	84041924	
	1985	0.02274	340300.	3165700.	85082224	
	1986	0.02141	342000.	3174000.	86080324	
HSH 24-Hour						
	1982	0.02137	343700.	3178300.	82062524	
	1983	0.01770	341100.	3183400.	83090424	
	1984	0.01389	343000.	3176200.	84050224	
	1985	0.01630	340300.	3165700.	85082124	
	1986	0.01888	342000.	3174000.	86053024	
SOURCE GROUP ID:	CT100					100°F
Annual						
	1982	$\boxed{0.00144}$	340300.	3165700.	82------	
	1983	0.00099	343700.	3178300.	83------	
	1984	0.00094	340300.	3165700.	84------	
	1985	0.00094	340300.	3165700.	85------	
	1986	0.00129	340300.	3165700.	86------	
HIGH 24-Hour						
	1982	$\boxed{0.02518}$	340300.	3165700.	82081424	
	1983	0.01930	343700.	3178300.	83090424	
	1984	0.01801	343000.	3176200.	84041924	
	1985	0.02389	340300.	3165700.	85082224	
	1986	0.02200	342000.	3174000.	86080324	
HSH 24-Hour						
	1982	0.02251	343700.	3178300.	82062524	
	1983	0.01840	342400.	3180600.	83120224	
	1984	0.01464	343000.	3176200.	84050224	
	1985	0.01697	340300.	3165700.	85082124	
	1986	0.01967	342000.	3174000.	86053024	
SOURCE GROUP ID:	AUXBLR					AUX. BLR.
Annual						
	1982	0.00021	340300.	3165700.	82------	
	1983	0.00014	343700.	3178300.	83------	

	1984	0.00013	340300.	3165700.	84------
	1985	0.00013	340300.	3165700.	85------
	1986	0.00020	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.00505	343700.	3178300.	82072924
	1983	0.00314	341100.	3183400.	83120224
	1984	0.00298	343000.	3176200.	84041924
	1985	0.00418	340300.	3165700.	85082224
	1986	0.00327	340300.	3167700.	86061224
HSH 24-Hour					
	1982	0.00399	343700.	3178300.	82062524
	1983	0.00308	342400.	3180600.	83090424
	1984	0.00260	343000.	3176200.	84050224
	1985	0.00274	340300.	3165700.	85082124
	1986	0.00321	342000.	3174000.	86080324

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCWIC1NO.082
ISCST2 OUTPUT FILE NUMBER 2 :OCWIC1NO.083
ISCST2 OUTPUT FILE NUMBER 3 :OCWIC1NO.084
ISCST2 OUTPUT FILE NUMBER 4 :OCWIC1NO.085
ISCST2 OUTPUT FILE NUMBER 5 :OCWIC1NO.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / CLASS 1 / COMBINED CYCLE-WATER INJ / NO2
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)	
SOURCE GROUP ID: ALL040						40°F ALL
Annual						
	1982	0.01314	340300.	3165700.	82------	
	1983	0.00886	343700.	3178300.	83------	
	1984	0.00851	340300.	3165700.	84------	
	1985	0.00838	340300.	3165700.	85------	
	1986	0.01184	340300.	3165700.	86------	
SOURCE GROUP ID: ALL059						59°F ALL
Annual						
	1982	0.01284	340300.	3165700.	82------	
	1983	0.00874	343700.	3178300.	83------	
	1984	0.00838	340300.	3165700.	84------	
	1985	0.00814	340300.	3165700.	85------	
	1986	0.01164	340300.	3165700.	86------	
SOURCE GROUP ID: ALL100						100°F ALL
Annual						
	1982	0.01052	340300.	3165700.	82------	
	1983	0.00718	343700.	3178300.	83------	
	1984	0.00683	340300.	3165700.	84------	
	1985	0.00681	340300.	3165700.	85------	
	1986	0.00957	340300.	3165700.	86------	
SOURCE GROUP ID: CT040						40°F CT ONLY
Annual						
	1982	0.01050	340300.	3165700.	82------	
	1983	0.00707	343700.	3178300.	83------	
	1984	0.00682	340300.	3165700.	84------	
	1985	0.00672	340300.	3165700.	85------	
	1986	0.00930	340300.	3165700.	86------	
SOURCE GROUP ID: CT059						59°F CT ONLY
Annual						
	1982	0.01020	340300.	3165700.	82------	
	1983	0.00694	343700.	3178300.	83------	
	1984	0.00669	340300.	3165700.	84------	
	1985	0.00648	340300.	3165700.	85------	
	1986	0.00910	340300.	3165700.	86------	
SOURCE GROUP ID: CT100						100°F CT ONLY
Annual						
	1982	0.00787	340300.	3165700.	82------	
	1983	0.00539	343700.	3178300.	83------	
	1984	0.00514	340300.	3165700.	84------	
	1985	0.00515	340300.	3165700.	85------	
	1986	0.00703	340300.	3165700.	86------	
SOURCE GROUP ID: AUXBLR						AUX. BLR.
Annual						
	1982	0.00264	340300.	3165700.	82------	
	1983	0.00180	343700.	3178300.	83------	
	1984	0.00169	340300.	3165700.	84------	
	1985	0.00166	340300.	3165700.	85------	
	1986	0.00254	340300.	3165700.	86------	

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNC1PM.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNC1PM.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNC1PM.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNC1PM.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNC1PM.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / CLASS 1 / COMBINED CYCLE-DLNOX / PM
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.00161	340300.	3165700.	82------
	1983	0.00108	343700.	3178300.	83------
	1984	0.00104	340300.	3165700.	84------
	1985	0.00102	340300.	3165700.	85------
	1986	0.00145	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02829	340300.	3165700.	82081424
	1983	0.02170	343700.	3178300.	83090424
	1984	0.02018	343000.	3176200.	84041924
	1985	0.02684	340300.	3165700.	85082224
	1986	0.02458	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02527	343700.	3178300.	82062524
	1983	0.02065	342400.	3180600.	83120224
	1984	0.01644	343000.	3176200.	84050224
	1985	0.01900	340300.	3165700.	85082124
	1986	0.02208	342000.	3174000.	86053024
SOURCE GROUP ID: ALL059					
Annual					
	1982	0.00162	340300.	3165700.	82------
	1983	0.00110	343700.	3178300.	83------
	1984	0.00106	340300.	3165700.	84------
	1985	0.00103	340300.	3165700.	85------
	1986	0.00146	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02855	340300.	3165700.	82081424
	1983	0.02183	343700.	3178300.	83090424
	1984	0.02034	343000.	3176200.	84041924
	1985	0.02708	340300.	3165700.	85082224
	1986	0.02470	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02551	343700.	3178300.	82062524
	1983	0.02082	342400.	3180600.	83120224
	1984	0.01659	343000.	3176200.	84050224
	1985	0.01913	340300.	3165700.	85082124
	1986	0.02225	342000.	3174000.	86053024
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.00165	340300.	3165700.	82------
	1983	0.00113	343700.	3178300.	83------
	1984	0.00108	340300.	3165700.	84------
	1985	0.00108	340300.	3165700.	85------
	1986	0.00151	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02968	340300.	3165700.	82081424
	1983	0.02243	343700.	3178300.	83090424
	1984	0.02104	343000.	3176200.	84041924
	1985	0.02815	340300.	3165700.	85082224
	1986	0.02525	342000.	3174000.	86080324
HSH 24-Hour					

40°F ALL

59°F ALL

100°F ALL

	1982	0.02657	343700.	3178300.	82062524
	1983	0.02156	342400.	3180600.	83120224
	1984	0.01729	343000.	3176200.	84050224
	1985	0.01976	340300.	3165700.	85082124
	1986	0.02299	342000.	3174000.	86053024
SOURCE GROUP ID:	CT040				
Annual					
	1982	0.00140	340300.	3165700.	82------
	1983	0.00094	343700.	3178300.	83------
	1984	0.00091	340300.	3165700.	84------
	1985	0.00089	340300.	3165700.	85------
	1986	0.00125	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02389	340300.	3169800.	82122124
	1983	0.01860	343700.	3178300.	83090424
	1984	0.01720	343000.	3176200.	84041924
	1985	0.02266	340300.	3165700.	85082224
	1986	0.02137	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02129	343700.	3178300.	82062524
	1983	0.01766	341100.	3183400.	83090424
	1984	0.01384	343000.	3176200.	84050224
	1985	0.01625	340300.	3165700.	85082124
	1986	0.01882	342000.	3174000.	86053024
SOURCE GROUP ID:	CT059				
Annual					
	1982	0.00141	340300.	3165700.	82------
	1983	0.00096	343700.	3178300.	83------
	1984	0.00092	340300.	3165700.	84------
	1985	0.00090	340300.	3165700.	85------
	1986	0.00126	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02413	340300.	3165700.	82081424
	1983	0.01874	343700.	3178300.	83090424
	1984	0.01735	343000.	3176200.	84041924
	1985	0.02290	340300.	3165700.	85082224
	1986	0.02149	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02152	343700.	3178300.	82062524
	1983	0.01778	341100.	3183400.	83090424
	1984	0.01399	343000.	3176200.	84050224
	1985	0.01639	340300.	3165700.	85082124
	1986	0.01898	342000.	3174000.	86053024
SOURCE GROUP ID:	CT100				
Annual					
	1982	0.00144	340300.	3165700.	82------
	1983	0.00099	343700.	3178300.	83------
	1984	0.00094	340300.	3165700.	84------
	1985	0.00095	340300.	3165700.	85------
	1986	0.00131	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.02527	340300.	3165700.	82081424
	1983	0.01934	343700.	3178300.	83090424
	1984	0.01806	343000.	3176200.	84041924
	1985	0.02397	340300.	3165700.	85082224
	1986	0.02204	342000.	3174000.	86080324
HSH 24-Hour					
	1982	0.02258	343700.	3178300.	82062524
	1983	0.01845	342400.	3180600.	83120224
	1984	0.01469	343000.	3176200.	84050224
	1985	0.01702	340300.	3165700.	85082124
	1986	0.01972	342000.	3174000.	86053024
SOURCE GROUP ID:	AUXBLR				
Annual					
	1982	0.00021	340300.	3165700.	82------
	1983	0.00014	343700.	3178300.	83------

40°F CT ONLY

59°F CT ONLY

100°F CT ONLY

AUX. BLR

	1984	0.00013	340300.	3165700.	84------
	1985	0.00013	340300.	3165700.	85------
	1986	0.00020	340300.	3165700.	86------
HIGH 24-Hour					
	1982	0.00505	343700.	3178300.	82072924
	1983	0.00314	341100.	3183400.	83120224
	1984	0.00298	343000.	3176200.	84041924
	1985	0.00418	340300.	3165700.	85082224
	1986	0.00327	340300.	3167700.	86061224
HSH 24-Hour					
	1982	0.00399	343700.	3178300.	82062524
	1983	0.00308	342400.	3180600.	83090424
	1984	0.00260	343000.	3176200.	84050224
	1985	0.00274	340300.	3165700.	85082124
	1986	0.00321	342000.	3174000.	86080324

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB2 RELEASE 93165

ISCST2 OUTPUT FILE NUMBER 1 :OCDNC1NO.082
ISCST2 OUTPUT FILE NUMBER 2 :OCDNC1NO.083
ISCST2 OUTPUT FILE NUMBER 3 :OCDNC1NO.084
ISCST2 OUTPUT FILE NUMBER 4 :OCDNC1NO.085
ISCST2 OUTPUT FILE NUMBER 5 :OCDNC1NO.086
First title for first output file is 1982 ARK ENERGY-ORANGECO / CLASS 1 / COMBINED CYCLE-DLNOX / NO2
Second title for first output file is 40,59, and 100 DEG / 65' AUX and 100' HRSG STACKS.

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL040					
Annual					
	1982	0.01282	340300.	3165700.	82------
	1983	0.00861	343700.	3178300.	83------
	1984	0.00826	340300.	3165700.	84------
	1985	0.00813	340300.	3165700.	85------
	1986	0.01162	340300.	3165700.	86------
SOURCE GROUP ID: ALL059					
Annual					
	1982	0.01245	340300.	3165700.	82------
	1983	0.00848	343700.	3178300.	83------
	1984	0.00812	340300.	3165700.	84------
	1985	0.00789	340300.	3165700.	85------
	1986	0.01129	340300.	3165700.	86------
SOURCE GROUP ID: ALL100					
Annual					
	1982	0.01032	340300.	3165700.	82------
	1983	0.00705	343700.	3178300.	83------
	1984	0.00671	340300.	3165700.	84------
	1985	0.00669	340300.	3165700.	85------
	1986	0.00952	340300.	3165700.	86------
SOURCE GROUP ID: CT040					
Annual					
	1982	0.01018	340300.	3165700.	82------
	1983	0.00681	343700.	3178300.	83------
	1984	0.00657	340300.	3165700.	84------
	1985	0.00647	340300.	3165700.	85------
	1986	0.00908	340300.	3165700.	86------
SOURCE GROUP ID: CT059					
Annual					
	1982	0.00980	340300.	3165700.	82------
	1983	0.00668	343700.	3178300.	83------
	1984	0.00643	340300.	3165700.	84------
	1985	0.00623	340300.	3165700.	85------
	1986	0.00875	340300.	3165700.	86------
SOURCE GROUP ID: CT100					
Annual					
	1982	0.00768	340300.	3165700.	82------
	1983	0.00525	343700.	3178300.	83------
	1984	0.00502	340300.	3165700.	84------
	1985	0.00503	340300.	3165700.	85------
	1986	0.00697	340300.	3165700.	86------
SOURCE GROUP ID: AUXBLR					
Annual					
	1982	0.00264	340300.	3165700.	82------
	1983	0.00180	343700.	3178300.	83------
	1984	0.00169	340300.	3165700.	84------
	1985	0.00166	340300.	3165700.	85------
	1986	0.00254	340300.	3165700.	86------

40°F ALL

59°F ALL

100°F ALL

40°F CT ONLY

59°F CT ONLY

100°F CT ONLY

AUX. BLR.

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

APPENDIX C

BREEZEWAKE OUTPUT

1

RBRZWAKE
IBM-PC VERSION (2.1)

SERIAL NUMBER 7474 SOLD TO KBN
RUN NAME: ocss
RUN BEGAN ON 06-30-93 AT 12:48:20

BREEZE WAKE DOWNWASH ANALYSIS

The following options have been chosen:

(1) Calculations are made for the ISCST model.
(2) All stacks must be within 5L to be considered for direction specific downwash.
(3) Downwash is calculated in 360 radial directions.
(4) Buildings are combined.

Note: This analysis determines the direction specific downwash parameters for the flow vector pointing in the direction listed.

Round figures are converted into 8-sided figures for the downwash analysis.

Algorithms:

0 = No Downwash
1 = Huber-Snyder Downwash
2 = Schulman-Scire Downwash

Input Buildings

Description	Bldg #	Bldg Ht(m)	# of Corners	X(m)	Y(m)
HRSG North	1	17.07	4		
				-4.57	7.62
				-4.57	17.98
				-24.38	17.98
				-24.38	7.62
HRSG South	2	17.07	4		
				-4.57	-7.62
				-4.57	-17.98
				-24.38	-17.98
				-24.38	-7.62
Cooling Tower	3	16.31	4		
				12.19	69.80
				12.19	121.92
				-4.27	121.92
				-4.27	69.80
Raw Water Tank	4	16.31	8		
				-19.42	92.13
				-17.37	87.17
				-19.42	82.21
				-24.38	80.16
				-29.34	82.21

				-31.39	87.17
				-29.34	92.13
				-24.38	94.18
North LM6000	5	10.97	4		
				-48.77	4.57
				-48.77	21.03
				-57.61	21.03
				-57.61	4.57
South LM6000	6	10.97	4		
				-48.77	-4.57
				-48.77	-21.03
				-57.61	-21.03
				-57.61	-4.57
Plant Services	7	8.84	4		
				-57.61	59.74
				-57.61	84.12
				-89.31	84.12
				-89.31	59.74
Control Bldg	8	9.14	4		
				-56.08	30.48
				-56.08	39.62
				-68.28	39.62
				-68.28	30.48

1

Input Stacks

Stack ID #	Stack #	Stack Ht(m)	X(m)	Y(m)
1	1	18.29	-39.62	-12.80

Downwash Structures

Structure 1: Ht= 17.07 m, MPW= 41.06 m, GEP= 42.67 m

Contains the following buildings:
- Building # 1: HRSG North
- Building # 2: HRSG South

The following stacks are within 5L:
- Stack # 1: 1

Structure 2: Ht= 16.31 m, MPW= 57.46 m, GEP= 40.77 m

Contains the following buildings:
- Building # 3: Cooling Tower
- Building # 4: Raw Water Tank

The following stacks are within 5L:

Structure 3: Ht= 10.97 m, MPW= 42.98 m, GEP= 27.43 m

Contains the following buildings:
- Building # 5: North LM6000
- Building # 6: South LM6000

The following stacks are within 5L:
- Stack # 1: 1

Structure 4: Ht= 9.14 m, MPW= 63.71 m, GEP= 22.85 m

Contains the following buildings:
Building # 5: North LM6000
Building # 6: South LM6000
Building # 8: Control Bldg
The following stacks are within 5L:
Stack # 1: 1

Structure 5: Ht= 8.84 m, MPW= 39.99 m, GEP= 22.10 m

Contains the following buildings:
Building # 7: Plant Services
The following stacks are within 5L:

NUMBER OF SOURCES = 1
1 Stack ID # 1, Stack # 1

The Dominant Structure Within 5L is:
STRUC= 1 H= 17.07 W= 41.06 GEP= 42.67

Direction Specific Building Downwash

Degree	Structure #	Height	Width	GEP	Algorithm
10	1	17.07	28.44	42.67	2
20	1	17.07	33.15	42.67	2
30	1	17.07	36.85	42.67	2
40	1	17.07	39.44	42.67	2
50	1	17.07	40.82	42.67	2
60	1	17.07	41.06	42.67	2
70	1	17.07	40.91	42.67	2
80	1	17.07	39.68	42.67	2
90	1	17.07	37.55	42.67	2
100	1	17.07	39.86	42.67	2
110	1	17.07	40.96	42.67	2
120	1	17.07	41.06	42.67	2
130	1	17.07	40.74	42.67	2
140	1	17.07	39.23	42.67	2
150	3	10.97	30.85	27.43	1
160	3	10.97	25.18	27.43	1
170	3	10.97	18.75	27.43	1
180	0	.00	.00	.00	0
190	1	17.07	28.44	42.67	2
200	1	17.07	33.15	42.67	2
210	1	17.07	36.85	42.67	2
220	1	17.07	39.44	42.67	2
230	1	17.07	40.82	42.67	2
240	1	17.07	41.06	42.67	2
250	1	17.07	40.91	42.67	2
260	1	17.07	39.68	42.67	2
270	1	17.07	37.55	42.67	2
280	1	17.07	39.86	42.67	2
290	1	17.07	40.96	42.67	2
300	1	17.07	41.06	42.67	2
310	1	17.07	40.74	42.67	2
320	1	17.07	39.23	42.67	2
330	3	10.97	30.85	27.43	1
340	3	10.97	25.18	27.43	1
350	3	10.97	18.75	27.43	1
360	0	.00	.00	.00	0

```
                    Stack #   1
tack ID:  1,    Building Height: 17.070,    Building Width: 41.056
7.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.070
17.07017.07010.97010.97010.970.0000017.07017.07017.07017.07017.07017.070
17.07017.07017.07017.07017.07017.07017.07017.07010.97010.97010.970.00000
8.44233.15136.85339.43540.81941.05540.90939.68437.55039.86240.96341.055
40.73639.23030.84825.18318.753.0000028.44233.15136.85339.43540.81941.055
40.90939.68437.55039.86240.96341.05540.73639.23030.84825.18318.753.00000
                RUN ENDED ON 06-30-93 AT 12:48:22
```

RBRZWAKE
IBM-PC VERSION (2.1)

RUN NAME: occc
RUN BEGAN ON 06-30-93 AT 12:48:29

BREEZE WAKE DOWNWASH ANALYSIS

The following options have been chosen:

(1) Calculations are made for the ISCST model.
(2) All stacks must be within 5L to be considered for direction specific downwash.
(3) Downwash is calculated in 360 radial directions.
(4) Buildings are combined.

Note: This analysis determines the direction specific downwash parameters for the flow vector pointing in the direction listed.

Round figures are converted into 8-sided figures for the downwash analysis.

Algorithms:

0 = No Downwash
1 = Huber-Snyder Downwash
2 = Schulman-Scire Downwash

Input Buildings

Description	Bldg #	Bldg Ht(m)	# of Corners	X(m)	Y(m)
HRSG North	1	17.07	4		
				-4.57	7.62
				-4.57	17.98
				-24.38	17.98
				-24.38	7.62
HRSG South	2	17.07	4		
				-4.57	-7.62
				-4.57	-17.98
				-24.38	-17.98
				-24.38	-7.62
Cooling Tower	3	16.31	4		
				12.19	69.80
				12.19	121.92
				-4.27	121.92
				-4.27	69.80
Raw Water Tank	4	16.31	8		
				-19.42	92.13
				-17.37	87.17
				-19.42	82.21
				-24.38	80.16
				-29.34	82.21

				-31.39	87.17
				-29.34	92.13
				-24.38	94.18
North LM6000	5	10.97	4		
				-48.77	4.57
				-48.77	21.03
				-57.61	21.03
				-57.61	4.57
South LM6000	6	10.97	4		
				-48.77	-4.57
				-48.77	-21.03
				-57.61	-21.03
				-57.61	-4.57
Plant Services	7	8.84	4		
				-57.61	59.74
				-57.61	84.12
				-89.31	84.12
				-89.31	59.74
Control Bldg	8	9.14	4		
				-56.08	30.48
				-56.08	39.62
				-68.28	39.62
				-68.28	30.48

1

Input Stacks

Stack ID #	Stack #	Stack Ht(m)	X(m)	Y(m)
1	1	30.48	.00	12.80
2	2	30.48	.00	-12.80
3	3	19.81	-108.51	34.14

1

Downwash Structures

Structure 1: Ht= 17.07 m, MPW= 41.06 m, GEP= 42.67 m

Contains the following buildings:
Building # 1: HRSG North
Building # 2: HRSG South
The following stacks are within 5L:
Stack # 1: 1
Stack # 2: 2

Structure 2: Ht= 16.31 m, MPW= 57.46 m, GEP= 40.77 m

Contains the following buildings:
Building # 3: Cooling Tower
Building # 4: Raw Water Tank
The following stacks are within 5L:
Stack # 1: 1

Structure 3: Ht= 10.97 m, MPW= 42.98 m, GEP= 27.43 m

Contains the following buildings:
Building # 5: North LM6000
Building # 6: South LM6000

The following stacks are within 5L:
Stack # 1: 1
Stack # 2: 2
Stack # 3: 3

Structure 4: Ht= 9.14 m, MPW= 63.71 m, GEP= 22.85 m

Contains the following buildings:
Building # 5: North LM6000
Building # 6: South LM6000
Building # 8: Control Bldg
The following stacks are within 5L:
Stack # 3: 3

Structure 5: Ht= 8.84 m, MPW= 39.99 m, GEP= 22.10 m

Contains the following buildings:
Building # 7: Plant Services
The following stacks are within 5L:
Stack # 3: 3

NUMBER OF SOURCES = 3
Stack ID # 1, Stack # 1

The Dominant Structure Within 5L is:
STRUC= 1 H= 17.07 W= 41.06 GEP= 42.67

Direction Specific Building Downwash

Degree	Structure #	Height	Width	GEP	Algorithm
10	1	17.07	28.44	42.67	1
20	1	17.07	33.15	42.67	1
30	1	17.07	36.85	42.67	1
40	1	17.07	39.44	42.67	1
50	1	17.07	40.82	42.67	1
60	1	17.07	41.06	42.67	1
70	1	17.07	40.91	42.67	1
80	1	17.07	39.68	42.67	1
90	1	17.07	37.55	42.67	1
100	1	17.07	39.86	42.67	1
110	1	17.07	40.96	42.67	1
120	1	17.07	41.06	42.67	1
130	1	17.07	40.74	42.67	1
140	1	17.07	39.23	42.67	1
150	1	17.07	36.53	42.67	1
160	1	17.07	32.72	42.67	1
170	1	17.07	27.92	42.67	1
180	1	17.07	22.87	42.67	1
190	1	17.07	28.44	42.67	1
200	1	17.07	33.15	42.67	1
210	1	17.07	36.85	42.67	1
220	1	17.07	39.44	42.67	1
230	1	17.07	40.82	42.67	1
240	1	17.07	41.06	42.67	1
250	1	17.07	40.91	42.67	1
260	1	17.07	39.68	42.67	1
270	1	17.07	37.55	42.67	1
280	1	17.07	39.86	42.67	1
290	1	17.07	40.96	42.67	1
300	1	17.07	41.06	42.67	1

310	1	17.07	40.74	42.67	1
320	1	17.07	39.23	42.67	1
330	1	17.07	36.53	42.67	1
340	1	17.07	32.72	42.67	1
350	1	17.07	27.92	42.67	1
360	1	17.07	22.87	42.67	1

1 Stack ID # 2, Stack # 2

The Dominant Structure Within 5L is:
STRUC= 1 H= 17.07 W= 41.06 GEP= 42.67

Direction Specific Building Downwash

Degree	Structure #	Height	Width	GEP	Algorithm
10	1	17.07	28.44	42.67	1
20	1	17.07	33.15	42.67	1
30	1	17.07	36.85	42.67	1
40	1	17.07	39.44	42.67	1
50	1	17.07	40.82	42.67	1
60	1	17.07	41.06	42.67	1
70	1	17.07	40.91	42.67	1
80	1	17.07	39.68	42.67	1
90	1	17.07	37.55	42.67	1
100	1	17.07	39.86	42.67	1
110	1	17.07	40.96	42.67	1
120	1	17.07	41.06	42.67	1
130	1	17.07	40.74	42.67	1
140	1	17.07	39.23	42.67	1
150	1	17.07	36.53	42.67	1
160	1	17.07	32.72	42.67	1
170	1	17.07	27.92	42.67	1
180	1	17.07	22.87	42.67	1
190	1	17.07	28.44	42.67	1
200	1	17.07	33.15	42.67	1
210	1	17.07	36.85	42.67	1
220	1	17.07	39.44	42.67	1
230	1	17.07	40.82	42.67	1
240	1	17.07	41.06	42.67	1
250	1	17.07	40.91	42.67	1
260	1	17.07	39.68	42.67	1
270	1	17.07	37.55	42.67	1
280	1	17.07	39.86	42.67	1
290	1	17.07	40.96	42.67	1
300	1	17.07	41.06	42.67	1
310	1	17.07	40.74	42.67	1
320	1	17.07	39.23	42.67	1
330	1	17.07	36.53	42.67	1
340	1	17.07	32.72	42.67	1
350	1	17.07	27.92	42.67	1
360	1	17.07	22.87	42.67	1

1 Stack ID # 3, Stack # 3

The Dominant Structure Within 5L is:
STRUC= 3 H= 10.97 W= 42.98 GEP= 27.43

Direction Specific Building Downwash

Degree	Structure #	Height	Width	GEP	Algorithm

10	0	.00	.00	.00	0
20	0	.00	.00	.00	0
30	0	.00	.00	.00	0
40	0	.00	.00	.00	0
50	0	.00	.00	.00	0
60	0	.00	.00	.00	0
70	0	.00	.00	.00	0
80	0	.00	.00	.00	0
90	0	.00	.00	.00	0
100	0	.00	.00	.00	0
110	0	.00	.00	.00	0
120	0	.00	.00	.00	0
130	0	.00	.00	.00	0
140	0	.00	.00	.00	0
150	0	.00	.00	.00	0
160	0	.00	.00	.00	0
170	0	.00	.00	.00	0
180	0	.00	.00	.00	0
190	0	.00	.00	.00	0
200	5	8.84	39.03	22.10	1
210	5	8.84	39.95	22.10	1
220	5	8.84	39.99	22.10	1
230	5	8.84	39.56	22.10	1
240	5	8.84	37.94	22.10	1
250	5	8.84	35.17	22.10	1
260	4	9.14	63.57	22.85	1
270	4	9.14	61.86	22.85	1
280	3	10.97	42.98	27.43	1
290	3	10.97	42.87	27.43	1
300	3	10.97	41.68	27.43	1
310	3	10.97	39.22	27.43	1
320	3	10.97	35.58	27.43	1
330	0	.00	.00	.00	0
340	0	.00	.00	.00	0
350	0	.00	.00	.00	0
360	0	.00	.00	.00	0

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                          Stack #   1
Stack ID:  1,    Building Height: 17.070,    Building Width: 41.056
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                          Stack #   2
Stack ID:  2,    Building Height: 17.070,    Building Width: 41.056
17.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.070
17.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.070
17.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.07017.070
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                          Stack #   3
Stack ID:  3,    Building Height: 10.970,    Building Width: 42.979
.00000.00000.00000.00000.00000.00000.00000.00000.00000.00000.00000.00000
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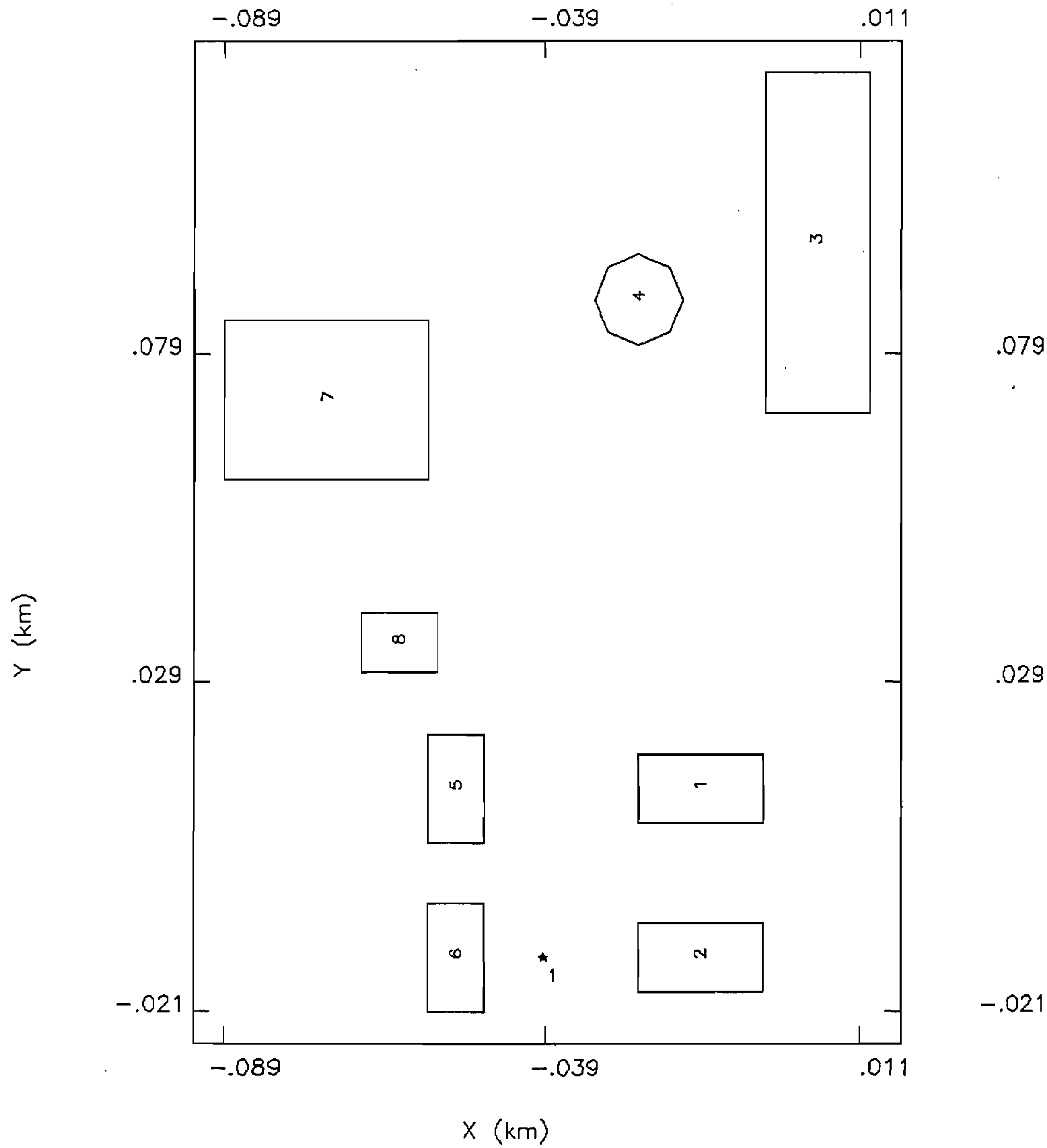
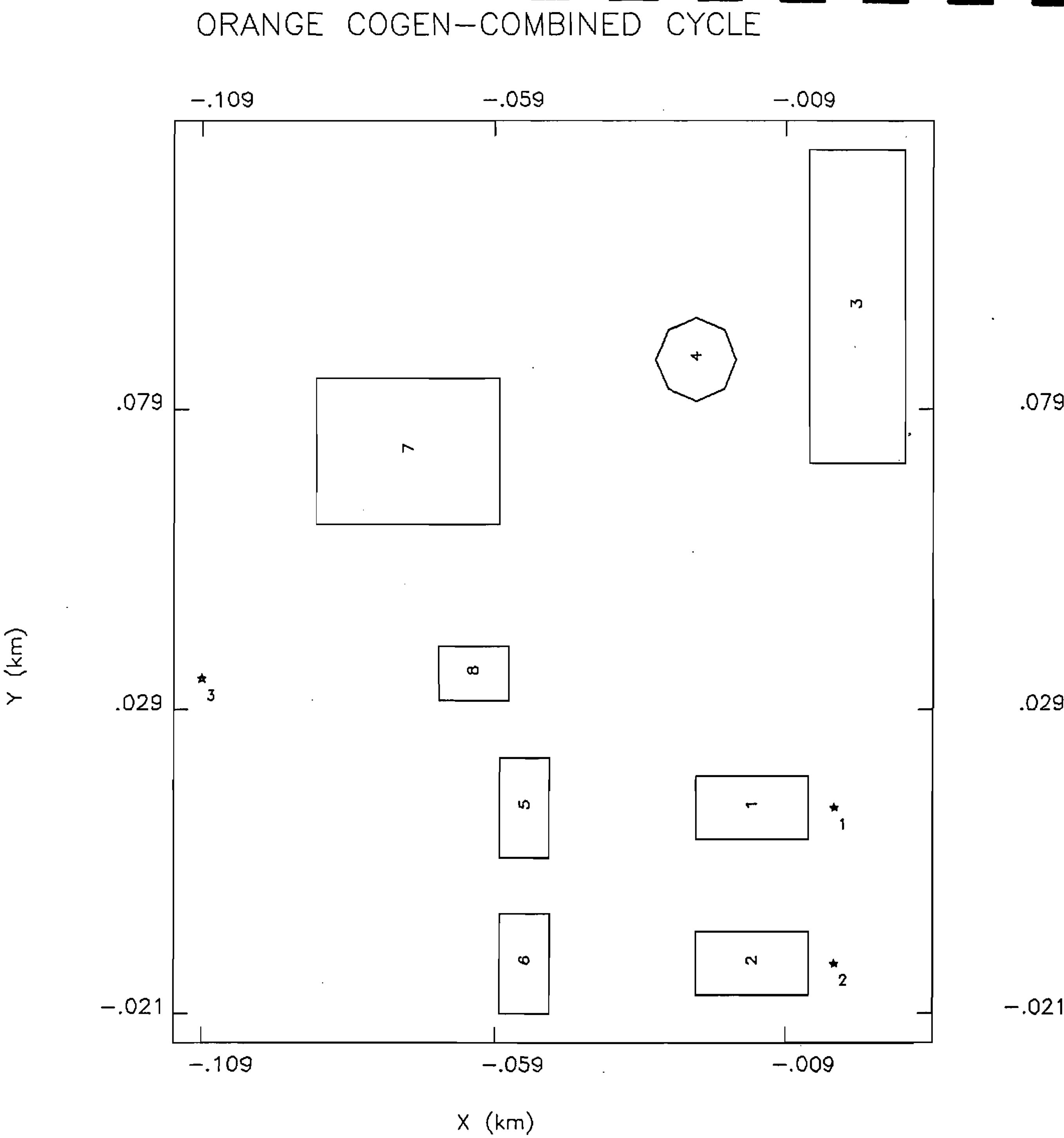
ORANGE COGEN-SIMPLE CYCLE




ORANGE COGEN–COMBINED CYCLE
–.109
–.059
–.009
.079
.029
–.021
Y (km)
X (km)
1
2
3
4
5
6
7
8

mittal of information under paragraphs (a) and (b) of this section in the amount calculated according to the following equations. Such allowances will be allocated to the refinery's non-unit subaccount for the calendar year in which the application is made.

(1) Allowances allocated under this section to any eligible refinery will be limited to the tons of SO_2 attributable to the desulfurization of diesel fuel at the refinery. (2) The refinery will be allocated allowances for a calendar year and, in the case of 1993, for the period October 1 through December 31, calculated according to the following equation, but not to exceed 1500 for any calendar year:

$$\text{Allowances Requested} = \frac{\left[\begin{matrix}(a)\\ \text{Diesel Fuel Production}\end{matrix}\right] \times \left[\begin{matrix}(b)\\ (302)\end{matrix}\right] \times \left[\begin{matrix}(c)\\ (0.00224)\end{matrix}\right] \times \left[\begin{matrix}(d)\\ (2)\end{matrix}\right]}{\left[\begin{matrix}2000\\ (e)\end{matrix}\right]}$$

Where:

- a=diesel fuel in barrels for the year (or for October 1 through December 31 for 1993)
- b=lbs per barrel of diesel
- c=lbs of sulfur per lbs of diesel
- d=lbs of SO_2 per lbs of sulfur
- e=lbs per short ton

(3) If applications for a given year request, in the aggregate, more than 35,000 allowances, the Administrator will allocate allowances to each refinery in the amount equal to the lesser of 1500 or:

$$\text{Refinery Allowances} = \text{the lesser of} \left[\begin{matrix}\text{Allowances Requested} \times \dfrac{\text{Total Allowances Requested}}{35{,}000}\\ \text{or}\\ 1{,}500\end{matrix}\right]$$

[58 FR 15716, Mar. 23, 1993; 58 FR 33770, June 21, 1993]

PART 75—CONTINUOUS EMISSION MONITORING

Subpart A—General

Sec.

Subpart B—Monitoring Provisions

Sec.

Subpart C—Operation and Maintenance Requirements

Sec.

Subpart D—Missing Data Substitution Procedures

Subpart E—Alternative Monitoring Systems

Subpart F—Recordkeeping Requirements

Subpart G—Reporting Requirements

Sec.

AUTHORITY: 42 U.S.C. 7651, *et seq.*

SOURCE: 58 FR 3701, Jan. 11, 1993, unless otherwise noted.

EDITORIAL NOTE: Part 75 was added at 58 FR 3701, Jan. 11, 1993, effective February 10, 1993. A document which corrected the January 11, 1993 document was published at 58 FR 40746, July 30, 1993, effective on the date of publication. Therefore, it should be noted that sections which reference July 30, 1993 in the source note are corrections to the January 11, 1993 document and are effective July 30, 1993.

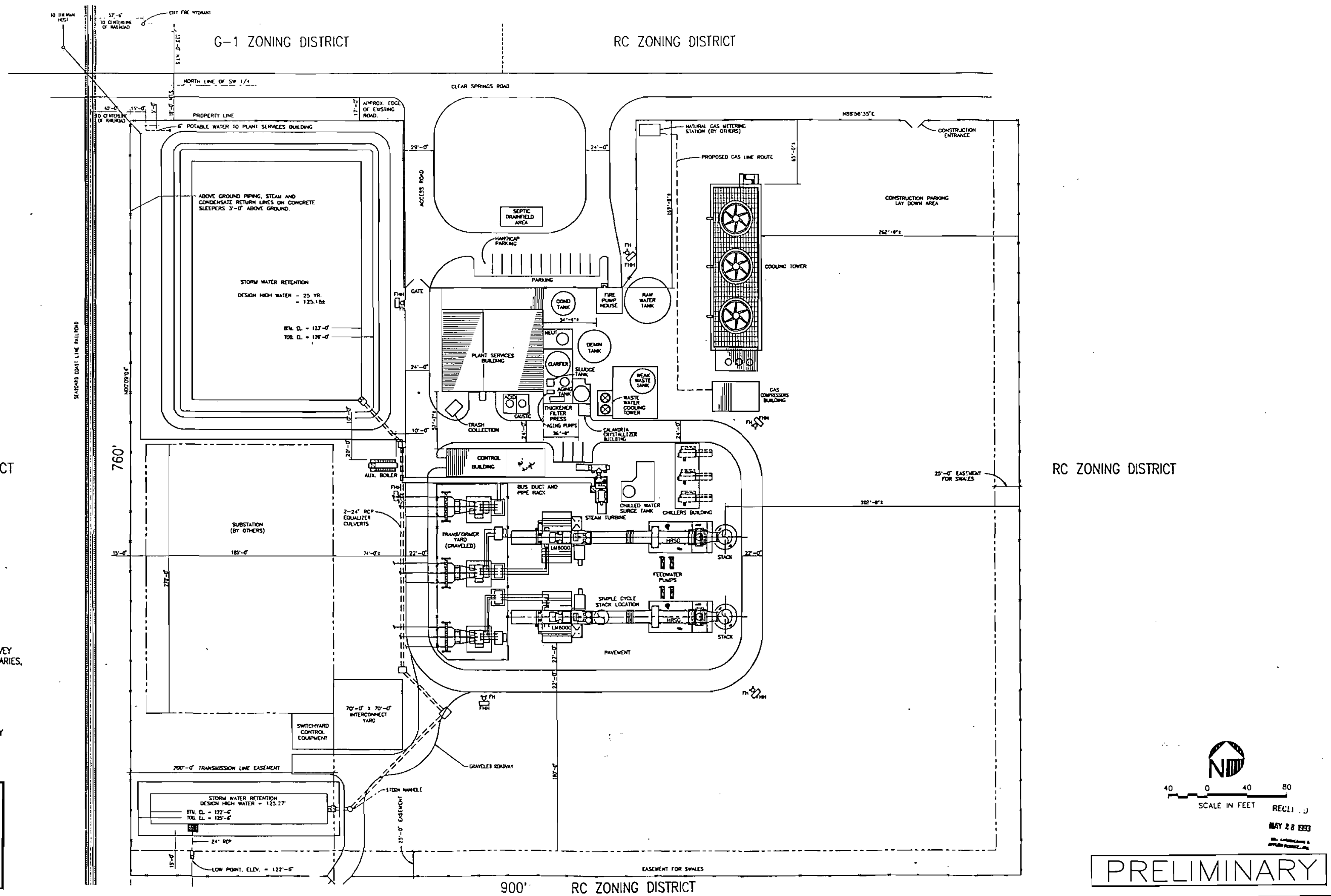
Subpart A—General

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to Sections 412 and 821 of the Clean Air Act, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 [November 15, 1990] [the Act].

(b) *Scope.* (1) The regulations established under this part include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems and specific requirements for the monitoring of SO_2 emissions, volumetric flow, NO_x emissions, opacity, CO_2 emissions and SO_2 emissions removal by qualifying Phase I technologies. Specifications for the installation and performance of continuous emission monitoring systems, certification tests and procedures, and quality assurance tests and procedures

06-30-93



NOTE:

1. ALL DIMENSIONS ARE APPROXIMATE, FINAL SURVEY WILL BE USED TO FIX SUCH ITEMS AS BOUNDARIES, BUILDING SPACING AND ROAD WIDTHS
2. FIRE PROTECTION SYSTEM INCLUDES HYDRANTS LOCATED AS SHOWN
   FH = FIRE HYDRANT
   FHH = FIRE HOSE HOUSE
3. POWER PLANT IS NATURAL GAS FIRED.
4. PROJECT SITE IS LOCATED WITHIN POLK COUNTY RC ZONING.
5. N.T.S. = NOT TO SCALE

Date:	5/17/93
Drawn By:	T. ALEXANDER
Checked By:	
Approved By:	

Figure 2-2 SITE LAYOUT

KBN