Jonathan H.

Florida Department of

Memorandum Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy CHF
Scott Sheplak SMS 8/16

FROM: Jonathan Holtom J.H.

DATE: August 15, 2000

BAR

SUBJECT: Final Construction Permit for Tiger Bay Cogeneration Facility

Attached for approval and signature is a Final construction permit for Florida Power Corporation's Tiger Bay Cogeneration Facility. This project is for the installation of a natural gas-fired auxiliary package steam boiler in order to provide a backup supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons/year by imposition of an emissions limit of 0.1 lb/MMBtu and a limit of 6,000 hours per year.

The Public Notice requirements have been met on August 14, 2000, by publishing in The Ledger (in Polk County) on July 31. No comments have been received from the public in response to this Public Notice, and no petitions were filed for an Administrative Hearing.

I recommend your approval and signature.

Day 90 is September 13, 2000.

Attachments

/jh

FINAL DETERMINATION

Florida Power Corporation
Tiger Bay Cogeneration Facility
DEP File No. 1050223-009-AC

The Department distributed a public notice package on July 27, 2000, to allow the applicant to construct a 100 MMBtu/hr natural gas-fired auxiliary package steam boiler at the Florida power Corporation Tiger Bay Cogeneration Facility, located at 3219 State Road 630 East, Ft. Meade, Polk County. The Public Notice of Intent to Issue was published in The Ledger (Polk County) on July 31, 2000.

COMMENTS/CHANGES

No comments were received by the Department from the public.

Comments were received from the applicant by telephone on August 2, regarding the daily averaging time required by the permit for monitoring natural gas usage. There was a concern regarding the reliability of the gas totalizer that was being installed by the gas supplier to provide the required daily average gas usage. The issue has since been resolved. The gas supplier will be installing a more accurate flow meter capable of providing reliable daily averages.

Discussions within the Bureau resulted in some confusion regarding the intent of the Appendix BD – BACT Determination, attached to the permit. In order to remove the confusion, the appendix was revised to clearly indicate that it is Small Boiler BACT Determination issued pursuant to Rule 62-296.406, Florida Administrative Code, for the purpose of controlling particulate matter and sulfur dioxide emissions. Accordingly, the references in the permit to "Appendix BD – BACT Determination" have been changed to "Appendix BD – Small Boiler BACT Determination".

CONCLUSION

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

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
W. Jeffrey Pardue, Director
Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida
33733

4a. Article Number
Z 333 638 225

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

7. Date of Delivery
AUG 24 2000

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

ST. PETERSBURG, FL CALLER SERVICE

5. Received By: *(Print Name)*

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

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

Thank you for using Return Receipt Service.

Z 333 638 225

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

Sent to: W. Jeffrey Pardue	
Street & Number: P. O. Box 14042, MAC BB1A	
Post Office, State, & ZIP Code: St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: 8/22/00 Permit No.1050223-009-AC - FPC Tiger Bay Cogen. Facility	

PS Form **3800**, April 1995

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

W. Jeffrey Pardue, Director, Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

DEP File No. 1050223-009-AC
Tiger Bay Cogeneration Facility
Polk County

Enclosed is Final Permit Number 1050223-009-AC. This permit authorizes Florida Power Corporation to add a natural gas-fired auxiliary package steam boiler in order to provide a backup supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons/year.. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/22/00 to the person(s) listed:

Mr. W. Jeffrey Pardue, Director, Environmental Services, Florida Power Corporation *
Mr. J. Michael Kennedy, Florida Power Corporation
Mr. Bill Thomas, DEP, SWD
Mr. Gregg Worley, EPA

8/22/00 cc: Title V Reading File
NSRS Reading File
Jonathan Holtom

Clerk Stamp

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

Barbara J. Boutwell 8/22/00
(Clerk) (Date)

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE

Florida Power Corporation
Tiger Bay Cogeneration Facility
3219 State Road 630 East
Ft. Meade, Florida 33841
Authorized Representative:
W. Jeffrey Pardue, Director, Environmental Services

Permit No.	1050223-009-AC
Project	Package Steam Boiler
SIC No.	49, 4961
Expires:	*August 15, 2001*

PROJECT AND LOCATION

This permit authorizes Florida Power Corporation to construct a 100 MMBtu/hr natural gas-fired auxiliary steam boiler.
This facility is located at 3219 State Road 630 East, Ft. Meade, Polk County. The UTM coordinates are Zone 17; 416.20 km E; 3069.22 km N.

STATEMENT OF BASIS

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

APPENDICES

The attached appendices are a part of this permit:

Appendix A	NSPS General Provisions
Appendix BD	Small Boiler BACT Determination
Appendix GC	General Permit Conditions
Appendix SS	Stack Sampling Facilities (version dated 10/07/96)

Howard L. Rhodes, Director
Division of Air Resources
Management

FACILITY DESCRIPTION

This facility consists of a single combustion turbine (CT) that exhausts through a non-fired heat recovery steam generator (HRSG). The CT is permitted to burn natural gas or distillate fuel oil; however, the equipment needed to burn fuel oil has not yet been installed. The facility also operates a zero liquid discharge system that provides treatment of process wastewater and exhausts through a baghouse. Total capacity of the facility is 269.5 megawatts (MW), of which a nominal 184 MW are from the CT and a nominal 85.5 MW are provided by the HRSG.

PROJECT DETAILS

This permitting action is to add a package steam boiler to the facility. The emissions unit addressed by this permit is:

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
-003	100 MMBtu/hr Auxiliary Natural Gas-fired Package Steam Boiler

REGULATORY CLASSIFICATION

This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY). This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

This project is exempt from the requirements of Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), as discussed in the Technical Evaluation and Preliminary Determination dated July 18, 2000.

This facility is a major source of hazardous air pollutants (HAPs) and is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

The emissions unit included in this project is subject to regulation under the New Source Performance Standards, 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (effective June 9, 1989); and, Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Emissions Units (version dated March 2, 1999).

REVIEWING AND PROCESS SCHEDULE

May 17, 2000	Received permit application
May 17, 2000	Application complete
June 28, 2000	Received minor revision to application
July 27, 2000	Mailed Notice of Intent to Issue Air Construction Permit
July 31, 2000	Public Notice Posted in The Ledger (Polk County)
August 11, 2000	Received Proof of Publication of Notice of Intent

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- Permit application
- Applicant's additional information
- Department's Technical Evaluation and Preliminary Determination dated July 18, 2000
- Department's Intent to Issue

ADMINISTRATIVE

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, phone number 850/488-0114. All documents related to reports, tests, minor modifications and notifications shall be submitted to the Department's Southwest District office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218, and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes.
[Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.) regulations. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time.
[Rule 62-4.080, F.A.C.]

6. Expiration: This air construction permit shall expire on August 15, 2001. 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.
[Rules 62-210.300(1), 62-4.070(4) 62-4.080, and 62-4.210, F.A.C]

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification.
[Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. Title V Operation Permit Revision Required: This permit authorizes construction and/or installation of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit revision is required for regular operation of the permitted emissions unit. The owner or operator shall apply for a Title V operation permit revision at least ninety days prior to expiration of this construction permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit revision, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the DEP's Bureau of Air Regulation, and a copy sent to the Department's Southwest District office.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

9. Unconfined Emissions of Particulate Matter:
   (a) No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions.
   (b) Any permit issued to a facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter.
   (c) Reasonable precautions include the following:
      - Paving and maintenance of roads, parking areas and yards.
      - Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
      - Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
      - Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.
      - Landscaping or planting of vegetation.
      - Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
      - Confining abrasive blasting where possible.
      - Enclosure or covering of conveyor systems.
   (d) In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

   [Rule 62-296.320(4)(c), F.A.C.]

10. General Pollutant Emission Limiting Standards:
   (a) No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
   (b) No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
   [Rule 62-296.320(1)(a)&(2), F.A.C.]

   [Note: An objectionable odor is defined in Rule 62-210.200(198), F.A.C., as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance.]

OPERATIONAL REQUIREMENTS

11. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department's district office and, if applicable, appropriate local program. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules.
   [Rule 62-4.130, F.A.C.]

12. Circumvention: No person shall circumvent any air pollution control device or allow the emission of air pollutants without the applicable air pollution control device operating properly.
   [Rule 62-210.650, F.A.C.]

13. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers.
   [Rule 62-4.070(3), F.A.C.]

The following specific conditions apply to the following emissions unit after construction:

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
-003	100 MMBtu/hr Auxiliary Natural Gas-fired Package Steam Boiler

This emission unit is a 100 million Btu per hour (MMBtu/hr) package steam generation unit (boiler), manufactured by Cleaver-Brooks (Model DL-94). At 100 MMBtu/hr, this unit is capable of generating 85,000 pounds of steam. The purpose of this unit is to provide a back-up supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host.

[Note: Emissions unit -003 is subject to the reporting requirements of 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40c - 60.48c, effective June 9, 1989); 40 CFR 60 Subpart A (effective July 1, 1997); and, is subject to the requirements of the state rules as indicated in this permit. Stack height = 40 feet, exit diameter = 4.0 feet, exit temperature = 320°F, actual volumetric flow rate = 29,162 acfm.]

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

1. Permitted Capacity: The maximum operation heat input rate is as follows:

Unit No.	Daily Average Heat Input	Fuel Type
-003	100 MMBtu/hr	Natural Gas

[Rules 62-4.160(2), 62-210.200(PTE) & 62-296.406, F.A.C.; and, Applicant request.]

2. Hours of Operation: This emissions unit shall only operate up to 6,000 hours during any consecutive 12-month period.
[Rules 62-213.440 & 62-210.200, F.A.C., Definitions-potential to emit (PTE); and, applicant request in order to avoid PSD applicability.]

3. Fuel: Pipeline quality natural gas is the only fuel allowed to be fired in the auxiliary boiler.
[Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE); and, applicant request in order to avoid PSD applicability.]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

4. Visible Emissions: Visible Emissions shall not exceed 20 percent opacity except for one six-minute period per hour during which opacity shall not exceed 27 percent.
[Rule 62-296.406(1), F.A.C.; and, applicant request dated July 20, 2000.]

5. Particulate Matter: Particulate Matter emissions shall be controlled by the firing of natural gas, as specified in the attached Appendix BD – Small Boiler BACT Determination.
[Rule 62-296.406(2), F.A.C.; and, BACT.]

6. Sulfur Dioxide: Sulfur Dioxide emissions shall be controlled by the firing of natural gas, as specified in the attached Appendix BD – Small Boiler BACT Determination.
[Rule 62-296.406(3), F.A.C.; and, BACT.]

7. Nitrogen Oxides: Nitrogen oxide emissions shall not exceed 0.10 lb/MMBtu, as measured by applicable compliance methods.
[Rule 62-4.070(3), F.A.C.; and, applicant request to avoid PSD applicability.]

EXCESS EMISSIONS

[Note: The following excess emissions provisions can not be used to vary any NSPS requirements (from any subpart of 40 CFR 60).]

8. Excess emissions resulting from start-up, shutdown or malfunction of any emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

9. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during start-up, shutdown, or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

REQUIRED TESTS

10. Visible Emissions: Prior to applying for a Title V operation permit revision, and annually thereafter, Unit -003 shall be tested for visible emissions, in accordance with the requirements listed below.
[Rule 62-297.320(7)(a)4., F.A.C.]

11. Nitrogen Oxides Emissions: Prior to applying for a Title V operation permit revision or renewal, Unit -003 shall be tested for nitrogen oxides emissions, in accordance with the requirements listed below.
[Rule 62-297.320(7)(a)4., F.A.C.]

TEST METHODS AND PROCEDURES

12. Visible Emissions: The test method for visible emissions shall be DEP Method 9 (see specific condition 13.), incorporated in Chapter 62-297, F.A.C.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.]

13. DEP Method 9: The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
   (a) EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen-second intervals during the required period of observation.
   (b) EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 27 percent is permissible for not more than six minutes per hour) opacity shall be computed as follows:
      1. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
      2. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

   In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

   [Rule 62-297.401(9)(c), F.A.C.]

14. Nitrogen Oxides: The test method for Nitrogen oxide emissions shall be Method 7E, incorporated in Chapter 62-297, F.A.C.
   [Rule 62-297.401(7)(e), F.A.C.]

COMPLIANCE TEST REQUIREMENTS

15. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of

compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard.
[Rule 62-297.310(1), F.A.C.]

16. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C.]

17. Calculation of Emission Rate: The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

18. Applicable Test Procedures:
   (a) Required Sampling Time.
      1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
         a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
         b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
         c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

19. Determination of Process Variables:
    (a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
    (b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

20. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. Sampling facilities shall also conform to the requirements of attached Appendix SS.
    [Rule 62-297.310(6), F.A.C.]

21. Test Notification: The owner or operator shall notify the Department's district office and, if applicable, appropriate local program, at least 15 days prior to the date on which each formal compliance test is to begin. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
    [Rule 62-297.310(7)(a)9., F.A.C.; and, 40 CFR 60.8]

    [Note: The federal requirements of 40 CFR 60.8 require 30 days notice of the initial test and any tests required under section 114 of the Clean Air Act, but the Department rules require 15 days notice for the annual compliance tests. Unless otherwise advised by the district office or, if applicable, appropriate local program, provide 15 days notice prior to conducting annual tests, except for the initial test when 30 days notice is required.]

22. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department.
    [Rule 62-297.310(7)(b), F.A.C.]

REPORTING AND RECORD KEEPING REQUIREMENTS

23. Duration of Record Keeping: 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. 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 five years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
[Rules 62-4.160(14)(a)&(b) and 62-213.440(1)(b)2.b., F.A.C.]

24. Test Reports:
    (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
    (b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
    (c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
        1. The type, location, and designation of the emissions unit tested.
        2. The facility at which the emissions unit is located.
        3. The owner or operator of the emissions unit.
        4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
        5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission-limiting standard.
        6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
        7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
        8. The date, starting time and duration of each sampling run.
        9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
        10. The number of points sampled and configuration and location of the sampling plane.
        11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
        12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

25. <u>Excess Emissions Report</u>: If excess emissions occur, the owner or operator shall notify the Department within one working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A.
[Rule 62-4.130, F.A.C.]

26. <u>Excess Emissions Report - Malfunctions</u>: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate local program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

27. <u>Annual Operating Report for Air Pollutant Emitting Facility</u>: The Annual Operating Report for Air Pollutant Emitting Facility shall be completed each year and shall be submitted to the Department's Southwest District office by March 1 of the following year.
[Rule 62-210.370(3), F.A.C.]

28. <u>Notification Requirements</u>:
    (a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by 40 CFR 60.7 (see attached Appendix A). This notification shall include:
        (1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(b) – (f) [Reserved]

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(h) [Reserved]

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of five years following the date of such record.

(j) [Reserved]

[62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 60.48c.]

29. Records of Hours of Operation. The owner or operator shall maintain an operation log available for Department inspection that documents the hours of operation each day. This record shall equal the hours that fuel is fired. Within 10 days after the end of each month, a record shall be made of the hours of operation in the previous consecutive 12-month period.
[Rules 62-4.070(3) & 62-210.200(PTE), F.A.C.]

30. Records of Heat Input. The owner or operator shall maintain an operation log available for Department inspection that documents the average hourly heat input (higher heating value) to the boiler, as follows. At the end of each 24-hour period that the boiler operates, the average hourly heat input shall be calculated and recorded utilizing the quantity of fuel combusted (see condition 28(g)), the actual hours operated in the previous 24-hour period (see condition 29.), and the representative heat content (higher heating value) of the as-fired fuel. The heat content of the fuel can be obtained from either on-site testing or from the fuel supplier, as long as the information provided is representative of the as-fired fuel.
[Rules 62-4.070(3) & 62-210.200(PTE), F.A.C.]

[Note: The numbering of the original rules in the following conditions has been preserved for ease of reference to the rules. The term "Administrator" when used in 40 CFR 60 shall mean the Secretary or the Secretary's designee.]

1. Pursuant to 40 CFR 60.1 Applicability:
   (a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
   (b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
   (c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).
   [40 CFR 60.1]

2. Pursuant to 40 CFR 60.7 Notification And Record Keeping:
   (a) Any owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:
      (1) A notification of the date construction (or reconstruction as defined under 40 CFR 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
      (2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date.
      (3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.
      (4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
      (5) [Reserved]
      (6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for

the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7)[Reserved]

(b) The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) [Reserved]

(d) [Reserved]

(e) [Reserved]

(f) The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least three years following the date of such measurements, maintenance, reports, and records.

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[40 CFR 60.7]

3. Pursuant to 40 CFR 60.8 Performance Tests:

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance-testing facilities as follows: (1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures. (2) Safe sampling platform(s). (3) Safe access to sampling platform(s). (4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 CFR 60.8]

[See the note for specific condition 21 of Section II of this permit regarding the proper advance notification of compliance tests.]

4. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements:

(a) Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Reference Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected

facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) [Reserved]

(5) [Reserved]

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of paragraphs (a) through (e) of 40 CFR 60.11.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in 40 CFR 60, nothing in 40 CFR 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[40 CFR 60.11]

5. Pursuant to 40 CFR 60.12 Circumvention:
No owner or operator subject to the provisions of 40 CFR 60.12 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the

atmosphere.
[40 CFR 60.12]

6. Pursuant to 40 CFR 60.14 Modification:
   (a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.
   (b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:
      (1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.
      (2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.
   (c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.
   (d) [Reserved]
   (e) The following shall not, by themselves, be considered modifications under this part:
      (1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.
      (2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.
      (3) An increase in the hours of operation.
      (4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was

designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

[40 CFR 60.14]

7. <u>Pursuant to 40 CFR 60.15 Reconstruction</u>:

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost'" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.
(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:
(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 CFR 60.15]

8. Pursuant to 40 CFR 60.19 General notification and reporting requirements:
(a) For the purposes of 40 CFR 60, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.
(b) For the purposes of 40 CFR 60, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery agreed to by the permitting authority, is acceptable.
(c) Notwithstanding time periods or postmark deadlines specified in 40 CFR 60 for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.
(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under 40 CFR 60 to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under 40 CFR 60, the owner or operator may change the dates by which periodic reports under 40 CFR 60 shall be submitted (without changing the frequency of

reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in 40 CFR 60. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) [Reserved]

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of 40 CFR 60.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in 40 CFR 60.

(2) Notwithstanding time periods or postmark deadlines specified in 40 CFR 60 for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[40 CFR 60.19]

APPENDIX BD – SMALL BOILER BACT DETERMINATION

Best Available Control Technology (BACT) Determination
Florida Power Corporation
Tiger Bay Cogeneration Facility, Polk County

This BACT determination is required for the source as set forth in the Rule 62-296.406, Florida Administrative Code (F.A.C.), Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources.

Description of Project:

The applicant is proposing to add a natural gas-fired package steam boiler to the facility. The purpose of this boiler is to provide a back-up supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr.

The construction permit application is being processed by the Tallahassee office. The application and BACT proposal were received in the Bureau of Air Regulation on May 17, 2000.

BACT Determination Requested by Applicant:

The applicant has proposed to limit particulate matter and sulfur dioxide emissions by firing only pipeline quality natural gas.

BACT Determination by DEP:

Pursuant to Rule 62-296.406, F.A.C., particulate matter and sulfur dioxide emissions shall be limited by the use of the Best Available Control Technology (BACT). BACT is based on the maximum achievable reduction in emissions taking into consideration energy, environmental and economic impacts. BACT for the package boiler shall be the use of natural gas as the exclusive fuel. Fuel oil shall not be fired in the package boiler and the owner or operator of the facility shall not connect a fuel oil supply to this boiler. The Department's compliance inspectors should verify that a fuel oil supply line is not provided to this unit.

BACT Determination Rationale:

Sulfur in fuel is a primary air pollution concern since most of the fuel sulfur becomes sulfur dioxide. Also, particulate matter emissions from fuel burning are related to the sulfur content. BACT for particulate matter and sulfur dioxide, the two pollutants regulated pursuant to Rule 62-296.406, F.A.C., is the use of a very low sulfur fuel such as natural gas. Burning of natural gas results in relatively lower emissions of other criteria pollutants as compared with firing fuel oil, with the exception of nitrogen oxides, which are higher. Carbon monoxide emissions appear to be slightly higher for natural gas until one accounts for the potential increase in CO emissions that would result from improper boiler operation or poor boiler maintenance while firing fuel oil. The emission factor for CO emissions from firing fuel oil must be adjusted upward by a factor of 10 to 100 to account for this possibility. Thus, for the majority of pollutants, including particulate matter and sulfur dioxide, the use of natural gas is the best alternative.

Best Available Control Technology (BACT) Determination
Florida Power Corporation
Tiger Bay Cogeneration Facility, Polk County

Details of the Analysis May be Obtained by Contacting:

Jonathan Holtom, P.E.
Department of Environmental Protection
Division of Air Resources Management
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850-921-9531

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

8/18/00
Date

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

8/20/00
Date

APPENDIX GC – GENERAL PERMIT CONDITIONS
[F.A.C. 62-4.160]

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

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey 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 or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

(c) Records of monitoring information shall include:

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

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

Stack Sampling Facilities Provided by the Owner of an Emissions Unit. This section describes the minimum requirements for stack sampling facilities that are necessary to sample point emissions units. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. Emissions units must provide these facilities at their expense. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.
2. The ports shall be capable of being sealed when not in use.
3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45-degree angle.
5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d) Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e) Access to Work Platform.
1. Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f) Electrical Power.
1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.
2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g) Sampling Equipment Support.
1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.
   a. The bracket shall be a standard 3-inch x 3-inch x one-quarter inch equal-legs bracket, which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.
   b. A three-eighth inch bolt, which protrudes 2 inches from the stack, may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.
   c. The three-quarter inch eyebolt shall be capable of supporting a 500-pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.
2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.
3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

Florida Power
CORPORATION

June 23, 2000

Mr. Jonathan Holtom, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Holtom:

Re: Package Boiler Permit Application - FPC Tiger Bay Facility

As we discussed, enclosed are four originals of the appropriate pages of a modified construction permit application for the installation of a small, natural gas-fired package steam boiler at Florida Power Corporation's (FPC) Tiger Bay facility. The modification is a reduction in the proposed maximum annual hours of operation from 7,980 to 6,000. The pages affected by this change have been updated accordingly, including the potential annual pollutant emissions.

Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

ONE POWER PLAZA, 263 - 13th Avenue South, BB1A, St. Petersburg, FL 33701-5511 •
P.O. Box 14042, BB1A • St. Petersburg • Florida 33733-4042 • (727) 820-5151
A Florida Progress Company

Department of Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Florida Power Corporation	
2. Site Name : Tiger Bay Facility	
3. Facility Identification Number : 1050223	[ ] Unknown
4. Facility Location : Ft. Meade Street Address or Other Locator : 3219 State Road 630 East City : Ft. Meade County : Polk Zip Code : 33841	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official : Name : W. Jeffrey Pardue, C.E.P. Title : Director, Environmental Services
2. Owner or Authorized Representative or Responsible Official Mailing Address : Organization/Firm : Florida Power Corporation Street Address : P.O. Box 14042, MAC BB1A City : St. Petersburg State : FL Zip Code : 33733
3. Owner/Authorized Representative or Responsible Official Telephone Numbers : Telephone : (727)826-4301 Fax : (727)826-4216
4. Owner/Authorized Representative or Responsible Official Statement : *I, the undersigned, am the owner or authorized representative* of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.* W J Pardue 6/23/00 Signature Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
004	Natural gas-fired package steam boiler	

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Emissions Unit Details

1. Initial Startup Date :		
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : Cleaver-Brooks		Model Number : DL-94
4. Generator Nameplate Rating :	MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	100	mmBtu/hr	
2. Maximum Incinerator Rate :		lb/hr	tons/day
3. Maximum Process or Throughput Rate :			
4. Maximum Production Rate :	85000	lbs steam/hr	
5. Operating Capacity Comment : Heat input capacity is 100 mmBtu/hr. Steam generating capacity is 85,000 lb/hr.			

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :		
	24 hours/day	7 days/week
	52 weeks/year	6,000 hours/year

Application Processing Fee

Check one :

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

Construction/Modification Information

1. Description of Proposed Project or Alterations : Addition of natural gas-fired package steam boiler for providing supplemental steam.	
2. Projected or Actual Date of Commencement of Construction :	01-Jul-2000
3. Projected Date of Completion of Construction :	30-Aug-2000

Professional Engineer Certification

1. Professional Engineer Name : Registration Number :	Jennifer A. Stenger 0052125		
2. Professional Engineer Mailing Address : Organization/Firm : Street Address : City :	 Florida Power Corporation P.O. Box 14042, MAC BB1A St. Petersburg	State : FL	Zip Code : 33733
3. Professional Engineer Telephone Numbers : Telephone :	(727)826-4132	Fax :	(727)826-4216

4. Professional Engineer Statement :

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

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

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

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

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

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

Jennifer A. Stenger
Signature
(seal)

6/23/00
Date

Application Contact

1. Name and Title of Application Contact : Name : J. Michael Kennedy, Q.E.P. Title : Manager, Air Programs
2. Application Contact Mailing Address : Organization/Firm : Florida Power Corporation Street Address : P.O. Box 14042, MAC BB1A City : St. Petersburg State : FL Zip Code : 33733
3. Application Contact Telephone Numbers : Telephone : (727)826-4334 Fax : (727)826-4216

Application Comment

This application is for the proposed addition of a natural gas-fired package steam boiler in order to provide a backup steam supply. The heat input capacity of the boiler is 100 mmBtu/hr, which subjects it to 40 CFR Part 60, Subpart Dc.

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Natural gas	
2. Source Classification Code (SCC) : ~~20100201~~ 10200602	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : ~~0.10~~ 96.	5. Maximum Annual Rate : 600.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash : 0.00
9. Million Btu per SCC Unit : 1,040	
10. Segment Comment :	

210.300(3)(a)2. <150 MM cuft to be exempt.

$0.1\ \text{MMCUFT} \times 1040\ \frac{\text{MMBTU}}{\text{CuFt}} = 104\ \frac{\text{MMBTU}}{\text{hr}} \times 0.1\ \frac{\text{lb}}{\text{MMBTU}} = 10.4\ \frac{\text{lb}}{\text{hr}}$

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

$10.4\ \frac{\text{lb}}{\text{hr}} \times 6000\ \frac{\text{hrs}}{\text{yr}} \div 2000\ \frac{\text{lb}}{\text{Ton}} = 31.2\ \text{tpy}$

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO2			EL
2 - NOX			EL
3 - PM			EL
4 - PM10			EL
5 - CO			EL
6 - VOC			EL
7 - SAM			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.1400000 lb/hour	0.4200000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 1 Units : gr/100 CF Reference : Fuel analysis	
7. Emissions Method Code : 2	
8. Calculations of Emissions : Assumed max. S content of 1 gr/100 CF and 6000 hours of operation/year.	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **NOX**		
2. Total Percent Efficiency of Control : 0.00 %		
3. Potential Emissions :	10.0000000 lb/hour	30.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions:	to	tons/year
6. Emissions Factor 0 Reference : Manufacturer data	Units : lb/mmBtu	
7. Emissions Method Code : 0		
8. Calculations of Emissions : NOx emissions of 0.10 lb/mmBtu from manufacturer data. Annual max. tons of NOx from max. heat input of 100 mmBtu/hr and 6000 hours/year operation.		
9. Pollutant Potential/Estimated Emissions Comment :		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **PM10**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 0.8000000 lb/hour 2.4000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor 8 Units : lb/mmCF Reference : AP-42, nat. gas fire
7. Emissions Method Code : 3
8. Calculations of Emissions : AP-42 factor for PM (assume all PM is PM10) of 8 lb/mmCF and boiler capacity of 0.10 mmCF/hour. Annual emissions based on hourly rate times 6,000 hours/year.
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **CO**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 8.4000000 lb/hour	25.2000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 84 Reference : AP-42	Units : lb/mmCF
7. Emissions Method Code : 3	
8. Calculations of Emissions : AP-42 factor of 84 lb/mmCF and max. nat. gas firing capacity of 0.10 mmCF/hr. Annual emissions from hourly rate times 6,000 hours/year.	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **VOC**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.6000000 lb/hour	1.8000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 6 Reference : AP-42	Units : lb/mmCF
7. Emissions Method Code : 3	
8. Calculations of Emissions : AP-42 factor of 6 lb/mmCF and max. nat. gas firing capacity of 0.10 mmCF/hr. Annual emissions from hourly rate times 6,000 hours/year.	
9. Pollutant Potential/Estimated Emissions Comment :	

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

S02

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.00	grain S/100 CF		
4. Equivalent Allowable Emissions :	0.14	lb/hour	0.42	tons/year
5. Method of Compliance : Fuel analysis				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable based on max. sulfur content of 1 gr/100 CF of natural gas.				

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

NOx

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		ESCPSD		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		0.10	lb/mmBtu	
4. Equivalent Allowable Emissions :	10.00	lb/hour	30.00	tons/year
5. Method of Compliance : Stack test, ~~EPA Method 20~~ 7E * per Mike K. 7/18/00 Telecon.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Based on emission rate of 0.10 lb/mmBtu and 6000 hours/year.				

$30 \text{ tons} = 60{,}000 \text{ lb/yr} \div 6000 \text{ hrs} = 10 \frac{\text{lb}}{\text{hr}} \div 0.1 \frac{\text{lb}}{\text{MMBtu}} = 100 \frac{\text{MMBtu}}{\text{hr}}$

$100 \frac{\text{MMBtu}}{\text{hr}} \div 1040 \frac{\text{Btu}}{\text{cu ft}} = 96153.85 \frac{\text{cu ft}}{\text{hr}} \times 600 \text{ hrs} = 576.923 \frac{\text{MM cf}}{\text{yr}}$

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

PM10

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		0.80	lb/hr	
4. Equivalent Allowable Emissions : 0.80	lb/hour	2.40	tons/year	
5. Method of Compliance : VE, EPA Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : If VE < 10%, stack test not required.				

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

CO

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	8.40	lb/hr		
4. Equivalent Allowable Emissions :	8.40	lb/hour	25.20	tons/year
5. Method of Compliance : Good combustion practices				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :				

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

VOC

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.60	lb/hr		
4. Equivalent Allowable Emissions :	0.60	lb/hour	1.80	tons/year
5. Method of Compliance : Good combustion practices				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :				

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

VE

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :	10
2. Basis for Allowable Opacity :	OTHER
3. Requested Allowable Opacity : Normal Conditions : 10 % Requested Exceptional Conditions : 0 % Maximum Period of Excess Opacity Allowed : min/hour	
4. Method of Compliance : Annual compliance test, EPA Method 9	
5. Visible Emissions Comment : VE limit under normal conditions at full load.	

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions :		%
Exceptional Conditions :	100	%
Maximum Period of Excess Opacity Allowed :	60	min/hour

? 27% for 1-6 min per hour Per Mike Kennedy 7/18/00

4. Method of Compliance :

EPA Method 9

5. Visible Emissions Comment :

1. Rule 62-210.700. 2. Max. period of excess opacity allowed - 2 hours/24 hours.

210.700 (1) 2 hrs in 24

1050223-009-AC

Florida Power
CORPORATION

RECEIVED
AUG 11 2000
BUREAU OF AIR REGULATION

August 8, 2000

Mr. Jonathan Holtom, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Holtom:

Re: Tiger Bay Auxiliary Boiler Construction Permit - Proof of Publication

I have enclosed the proof of publication of the Public Notice of Intent to Issue Air Construction Permit for Florida Power Corporation's Tiger Bay facility.

Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

BEST AVAILABLE COPY

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Nelson Kirkland, who on oath says that he is Classified Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Notice of Intent

in the matter of........
to Issue Air Construction Permit

DEP File No. 1050223-009-AC

in the..........

Court, was published in said newspaper in the issues of..........

7-31;2000

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk 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.

Signed.......
Nelson Kirkland
Classified Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 3rd day of August A.D. 20 00

Jennifer Clendening
Notary Public

JENNIFER L. CLENDENING
MY COMMISSION # CC 900938
EXPIRES: January 10, 2004
Bonded Thru Notary Public Underwriters

(Seal)

JENNIFER L. CLENDENING

My Commission Expires 1/10/04

7R740070 E282 Attn: Dianne Blyler

Attach Notice Here

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050223-009-AC

Florida Power Corporation
Tiger Bay Cogeneration Facility
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air cor struction permit to W. Jeffrey Pardue, Director, Environmental Services, for the Tiger Bay Cogeneratio Facility located at 3219 State Road 630 East, Ft. Meade, Polk County. The permit is to add a natural gas fired auxiliary package steam boiler in order to provide a backup supply of steam during periods of non operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/ corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_x will be limited to 3 tons/year in order to avoid PSD applicability. The applicant's mailing address is: P.O. Box 14042, MAC 881A St. Petersburg, Florida 33733.

A Best Available Control Technology (BACT) determination was required for particulate matter (PM and sulfur dioxide (SO_2) pursuant to Rule 62-296.406, F.A.C.

Nitrogen Oxides (NO_x) emissions will be restricted to 30 tons per year by limiting NO_x emissions to 0. lb/MMBtu and hours of operation to 6,000 per year. Emissions of sulfur dioxide (SO_2) and particulate matte (PM/PM_{10}) will be very low because of the exclusive firing of inherently clean burning pipeline quality natu ral gas. There will be no provisions for firing fuel oil.

Total emissions of pollutants shall not exceed the annual emission rates in tons per year:

Pollutant	Emissions	Increase (Decrease)	Specifically Limited?
PM/PM_{10}	2.40	2.40	No
SO_2	0.42	0.42	No
NO_x	30.0	30.0	Yes
VOC	1.80	1.80	No
CO	25.2	25.2	No

An air quality impact analysis was not conducted. Emissions from the facility will not consume PSD incre ment and will not significantly contribute to or cause a violation of any state or federal ambient air quality standards.

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

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

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

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

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

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

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

Dept. of Environmental Protection Bureau of Air Regulation Suite 4, 111 S. Magnolia Drive Tallahassee, Florida, 32301 Telephone: 850/488-0114 Fax: 850/922-6979	Dept. of Environmental Protection Southwest District 3804 Coconut Palm Drive Tampa, Florida 33619-8218 Telephone: 813/744-6100

The complete project file includes the application, technical evaluations, Draft permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, Title V Section, or the Department's reviewing engineer for this project, Jonathan Holtom, P.E., at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information.

E-282 - 7-31; 2000

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
W. Jeffrey Pardue, Director
Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733

4a. Article Number
Z 094 212 851

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

7. Date of Delivery
JUL 31 2000

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X [signature]

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

Thank you for using Return Receipt Service.

Z 094 212 851

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

Sent to	W. Jeffrey Pardue, Director
Street & Number	P.O. Box 14042, MAC BB1A
Post Office, State, & ZIP Code	St. Petersburg, FL 33733
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	7/27/00

DEP File No. 1050223-009-AC
Tiger Bay Cogeneration

PS Form 3800, April 1995

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:
Florida Power Corporation
Tiger Bay Cogeneration Facility

DRAFT Permit No.: 1050223-009-AC
Facility ID No.: 1050223

Project: Air Construction Permit – 100 MMBtu/hr. Natural Gas-fired Auxiliary Package Steam Boiler

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, and subject to the proposed permit conditions, provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).

JONATHAN K. HOLTOM CERTIFICATE NO 52664 STATE OF FLORIDA PROFESSIONAL ENGINEER

Jonathan K Holtom

7/26/00

Jonathan K. Holtom, P.E.
Registration Number: 0052664

Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 26, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

W. Jeffrey Pardue, Director, Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

Re: DEP File No. 1050223-009-AC
100 MMBtu/hr Natural Gas-fired Auxiliary Package Steam Boiler, Tiger Bay Cogeneration Facility

Dear Mr. Pardue:

Enclosed is one copy of the Draft air construction permit for the Tiger Bay Cogeneration Facility located at 3219 State Road 630 East, Ft. Meade, Polk County. The Technical Evaluation and Preliminary Determination, the Department's Intent to Issue Air Construction Permit and the Public Notice of Intent to Issue Air Construction Permit are also included.

The Public Notice of Intent to Issue Air Construction Permit must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Scott M. Sheplak, P.E., Administrator, Title V Section at the above letterhead address. If you have any other questions, please contact Jonathan Holtom, P.E. at 850/921-9531.

Sincerely,

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

CHF/jh

Enclosures

In the Matter of an
Application for Permit by:

W. Jeffrey Pardue, Director, Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

DEP File No. 1050223-009-AC
Tiger Bay Cogeneration Facility
Polk County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft permit attached) for the proposed project, detailed in the application specified above and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, W. Jeffrey, Director, Environmental Services, Florida Power Corporation, applied on May 17, 2000, to the Department for an air construction permit for its Tiger Bay Cogeneration Facility located at 3219 State Road 630 East, Ft. Meade, Polk County. The permit is to add a natural gas-fired auxiliary package steam boiler in order to provide a backup supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons/year.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to install and test the above described emissions unit.

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

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

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

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

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

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

Executed in Tallahassee, Florida.

Scott M. Sheplak

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/27/00 to the person(s) listed:

Mr. W. Jeffrey Pardue, Director, Environmental Services, Florida Power Corporation *
Mr. J. Michael Kennedy, Florida Power Corporation
Mr. Bill Thomas, DEP, SWD
Mr. Gregg Worley, EPA

Clerk Stamp

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

Barbara J. Boutwell 1/27/00
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050223-009-AC

Florida Power Corporation
Tiger Bay Cogeneration Facility
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to W. Jeffrey Pardue, Director, Environmental Services, for the Tiger Bay Cogeneration Facility located at 3219 State Road 630 East, Ft. Meade, Polk County. The permit is to add a natural gas-fired auxiliary package steam boiler in order to provide a backup supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons/year in order to avoid PSD applicability. The applicant's mailing address is: P.O. Box 14042, MAC BB1A,St. Petersburg, Florida 33733

A Best Available Control Technology (BACT) determination was required for particulate matter (PM) and sulfur dioxide (SO_2) pursuant to Rule 62-296.406, F.A.C.

Nitrogen Oxides (NO_X) emissions will be restricted to 30 tons per year by limiting NO_X emissions to 0.1 lb/MMBtu and hours of operation to 6,000 per year. Emissions of sulfur dioxide (SO_2) and particulate matter (PM/PM_{10}) will be very low because of the exclusive firing of inherently clean burning pipeline quality natural gas. There will be no provisions for firing fuel oil.

Total emissions of pollutants shall not exceed the annual emission rates in tons per year:

Pollutant	Emissions	Increase (Decrease)	Specifically Limited?
PM/PM_{10}	2.40	2.40	No
SO_2	0.42	0.42	No
NO_X	30.0	30.0	Yes
VOC	1.80	1.80	No
CO	25.2	25.2	No

An air quality impact analysis was not conducted. Emissions from the facility will not consume PSD increment and will not significantly contribute to or cause a violation of any state or federal ambient air quality standards.

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

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

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

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

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

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

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

Dept. of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100

The complete project file includes the application, technical evaluations, Draft permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, Title V Section, or the Department's reviewing engineer for this project, Jonathan Holtom, P.E., at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Florida Power Corporation

Tiger Bay Cogeneration Facility

Air Construction Permit to Install a 100 MMBtu/hr Natural Gas-Fired Package Steam Boiler

Polk County

DEP File No.: 1050223-009-AC

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

July 18, 2000

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Florida Power Corporation
Tiger Bay Cogeneration Facility
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

Authorized Representative: W. Jeffrey Pardue, Director, Environmental Services

1.2 REVIEWING AND PROCESS SCHEDULE

May 17, 2000	Received permit application
May 17, 2000	Application complete
June 28, 2000	Received minor revision to application

2. FACILITY INFORMATION

2.1 FACILITY LOCATION

The facility is located at 3219 State Road 630 East, Ft. Meade, Polk County. The UTM coordinates are Zone 17; 416.20 km E; 3069.22 km N.

2.2 STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

Industry Group No.	49	Electric, Gas And Sanitary Services
Industry No.	4961	Steam Supply

2.3 FACILITY CATEGORY

The facility consists of a single combustion turbine (CT) that exhausts through a non-fired heat recovery steam generator (HRSG). The CT is permitted to burn natural gas or distillate fuel oil, however, the equipment needed to burn fuel oil has not yet been installed. The facility also operates a zero liquid discharge system that provides treatment of process wastewater and exhausts through a baghouse. Total capacity of the facility is 269.5 megawatts (MW), of which a nominal 184 MW are from the CT and a nominal 85.5 MW are provided by the HRSG.

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

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

This facility is a major source of hazardous air pollutants (HAPs) and is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

3. PROJECT DESCRIPTION

This project addresses the following emissions unit(s):

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
-003	100 MMBtu/hr Auxiliary Natural Gas-fired Package Steam Boiler.

The applicant proposes to add a natural gas-fired package steam boiler in order to provide a backup supplemental steam supply at the facility. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons per year by restricting operation to 6,000 hours per year. Due to the use of natural gas fuel, the emissions of other pollutants will be quite low. The proposed package boiler was manufactured by Cleaver-Brooks (Model DL-94). The purpose of this unit is to provide a back-up supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host.

4. PROJECT EMISSIONS

The emissions associated with this project are the by-products of combustion of natural gas.

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

Pollutant	Past Actual (New Unit)	Future Potential Emissions	Maximum Emissions Change	PSD Significance Levels [1]	Subject to PSD Review?
NO_X	0	30.00	+30.00	40	No
CO	0	25.20	+25.20	100	No
PM/PM_{10}	0	2.40	+2.40	25/15	No
SO_2	0	0.42	+0.42	40	No
VOC	0	1.80	+1.80	40	No

[1] Florida Administrative Code 212.400-2.

The proposed project results in less-than-significant increases in PSD pollutants. Emission increases will occur for nitrogen oxides (NO_X) (synthetically limited to 30 tons per year by restricting operation to 6,000 hours per year), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC) will be less than the significant emission levels per Table 62-212.400-2, F.A.C. This project will emit negligible quantities of sulfuric acid mist (H_2SO_4 mist or SAM), fluorides, beryllium, mercury and lead. Therefore, the modification is not subject to PSD.

5. RULE APPLICABILITY

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

This facility is located in an area designated, in accordance with Rule 62-204.340, F.A.C., as attainment for the criteria pollutants ozone, PM_{10}, carbon monoxide, sulfur dioxide, and nitrogen dioxide; and, as unclassifiable for lead.

The proposed project is not subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD) as discussed above.

The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules.

5.1 STATE REGULATIONS

Chapter 62-4	Permits
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.200	Definitions
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-296.406	Fossil Fuel Steam Generators With Less Than 250 MMBtu/hr Heat Input
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods

5.2 FEDERAL RULES

40 CFR 60	NSPS Subpart(s) Dc – Standards Of Performance For Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR 60	Applicable Sections of Subpart A, General Requirements

6. AIR POLLUTION CONTROL TECHNIQUES

6.1 APPLICANT CONTROL TECHNOLOGY PROPOSAL

The applicant proposed to control air pollutant emissions through the use of proper combustion of natural gas to limit SO_2 and PM emissions; and by limiting emissions of NO_X and hours of operation to keep NO_X emissions below the significance level.

6.2 STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

The minimum project control technology basis is 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (NSPS). The Department adopted Subpart Dc by reference in Rule 62-204.800, F.A.C. This subpart does not impose any emission limits for natural gas fired units. No National Emission Standards for Hazardous Air Pollutants exist for this project.

6.3 POLLUTANT EMISSIONS

6.3.1 NITROGEN OXIDES (NO_X) EMISSIONS

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas because natural gas has little or no fuel nitrogen. Because natural gas will be the only fuel used, the fuel NO_X phenomenon is not important for this project.

Total NO_X emissions resulting from this project will be restricted below the PSD applicability levels by imposing an emissions limit of 0.1 lb/MMBtu, and by limiting operation to 6,000 hours per year.

6.3.2 PARTICULATE MATTER (PM/PM_{10}) & SULFUR DIOXIDE (SO_2) EMISSIONS

Particulate matter is generated by various physical and chemical processes during combustion. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}). SO_2 is formed during the combustion process from the sulfur that is contained in the fuel.

Natural gas will be the only fuel fired and is efficiently combusted. Natural gas is an inherently clean fuel that contains no ash and very little sulfur.

Emissions of PM and SO_2 are subject to BACT per Rule 62-296.406, F.A.C., as discussed in Appendix BD. The firing of natural gas has been chosen as BACT by the applicant, and the Department concurs.

6.3.3 CARBON MONOXIDE (CO) EMISSIONS

CO is emitted from combustion processes due to incomplete fuel combustion. Due to the size of this proposed unit, and the generally infrequent nature of its operational needs, CO will not be emitted in levels that would cause concern. At 6,000 hours per year, CO emissions are about 25 tons per year. If the annual hours were not limited, CO emissions would be about 37 tons per year, which is still less than half of the significant level (100 tons) that would subject this project to PSD review for CO emissions. Therefore, the firing of natural gas and good combustion practices are all that is required for this project for the control of CO emissions.

6.3.4 VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. Generally good combustion practices are used to control VOC emissions and that is the control strategy selected for this project.

6.3.5 EMISSIONS CONTROL TECHNIQUES

There are no add-on emissions controls required by this permitting action. Pollutant emissions will be controlled by the proper combustion of natural gas, and by limiting NO_X emissions and hours of operation.

6.4 COMPLIANCE PROCEDURES

Pollutant	Compliance Procedure
Visible Emissions	Method 9
NO_X	Method 7E (Initial performance & permit renewal)

6.5 EXCESS EMISSIONS

Pursuant to Rule 62-210.700 F.A.C., excess emissions are allowable under the following scenarios: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

7. SOURCE IMPACT ANALYSIS

An impact analysis was not required for this project because it is not subject to the requirements of PSD.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. The Department will issue a draft permit to the applicant that allows the installation of a package steam boiler fired exclusively on natural gas. The hours of operation will be limited to a maximum of 6,000 hours per year in order to limit potential NO_X emissions to 30 tons per year, thereby avoiding PSD applicability.

Jonathan Holtom, P.E.
Department of Environmental Protection
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850/921-9531

DRAFT

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE

Florida Power Corporation
Tiger Bay Cogeneration Facility
3219 State Road 630 East
Ft. Meade, Florida 33841
Authorized Representative:
W. Jeffrey Pardue, Director, Environmental Services

Permit No.	1050223-009-AC
Project	Package Steam Boiler
SIC No.	49, 4961
Expires:	*(12 months from issue date)*

PROJECT AND LOCATION

This permit authorizes Florida Power Corporation to construct a 100 MMBtu/hr natural gas-fired auxiliary steam boiler.
This facility is located at 3219 State Road 630 East, Ft. Meade, Polk County. The UTM coordinates are Zone 17; 416.20 km E; 3069.22 km N.

STATEMENT OF BASIS

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

APPENDICES

The attached appendices are a part of this permit:

Appendix A	NSPS General Provisions
Appendix BD	BACT Determination
Appendix GC	General Permit Conditions
Appendix SS	Stack Sampling Facilities (version dated 10/07/96)

Howard L. Rhodes, Director
Division of Air Resources
Management

ADMINISTRATIVE

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, phone number 850/488-0114. All documents related to reports, tests, minor modifications and notifications shall be submitted to the Department's Southwest District office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218, and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes.
[Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.) regulations. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time.
[Rule 62-4.080, F.A.C.]

6. Expiration: This air construction permit shall expire on *(12 months from issuance)*. 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.
[Rules 62-210.300(1), 62-4.070(4) 62-4.080, and 62-4.210, F.A.C]

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification.

[Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. Title V Operation Permit Revision Required: This permit authorizes construction and/or installation of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit revision is required for regular operation of the permitted emissions unit. The owner or operator shall apply for a Title V operation permit revision at least ninety days prior to expiration of this construction permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit revision, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the DEP's Bureau of Air Regulation, and a copy sent to the Department's Southwest District office.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

9. Unconfined Emissions of Particulate Matter:
   (a) No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions.
   (b) Any permit issued to a facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter.
   (c) Reasonable precautions include the following:
      - Paving and maintenance of roads, parking areas and yards.
      - Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
      - Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
      - Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.
      - Landscaping or planting of vegetation.
      - Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
      - Confining abrasive blasting where possible.
      - Enclosure or covering of conveyor systems.
   (d) In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.
   [Rule 62-296.320(4)(c), F.A.C.]

10. General Pollutant Emission Limiting Standards:

(a) No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
(b) No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor.

[Rule 62-296.320(1)(a)&(2), F.A.C.]

[Note: An objectionable odor is defined in Rule 62-210.200(198), F.A.C., as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance.]

OPERATIONAL REQUIREMENTS

11. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department's district office and, if applicable, appropriate local program. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules.
[Rule 62-4.130, F.A.C.]

12. Circumvention: No person shall circumvent any air pollution control device or allow the emission of air pollutants without the applicable air pollution control device operating properly.
[Rule 62-210.650, F.A.C.]

13. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers.
[Rule 62-4.070(3), F.A.C.]

The following specific conditions apply to the following emissions unit after construction:

EMISSIONS UNIT NO.	EMISSIONS UNIT DESCRIPTION
-003	100 MMBtu/hr Auxiliary Natural Gas-fired Package Steam Boiler

This emission unit is a 100 million Btu per hour (MMBtu/hr) package steam generation unit (boiler), manufactured by Cleaver-Brooks (Model DL-94). At 100 MMBtu/hr, this unit is capable of generating 85,000 pounds of steam. The purpose of this unit is to provide a back-up supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host.

[Note: Emissions unit -003 is subject to the reporting requirements of 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40c - 60.48c, effective June 9, 1989); 40 CFR 60 Subpart A (effective July 1, 1997); and, is subject to the requirements of the state rules as indicated in this permit. Stack height = 40 feet, exit diameter = 4.0 feet, exit temperature = 320°F, actual volumetric flow rate = 29,162 acfm.]

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

1. Permitted Capacity: The maximum operation heat input rate is as follows:

Unit No.	Daily Average Heat Input	Fuel Type
-003	100.00 MMBtu/hr	Natural Gas

   [Rules 62-4.160(2), 62-210.200(PTE) & 62-296.406, F.A.C.; and, Applicant request.]

2. Hours of Operation: This emissions unit shall only operate up to 6,000 hours during any consecutive 12-month period.
   [Rules 62-213.440 & 62-210.200, F.A.C., Definitions-potential to emit (PTE); and, applicant request in order to avoid PSD applicability.]

3. Fuel: Pipeline quality natural gas is the only fuel allowed to be fired in the auxiliary boiler.
   [Rule 62-210.200, F.A.C., Definitions-potential to emit (PTE); and, applicant request in order to avoid PSD applicability.]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

4. Visible Emissions: Visible Emissions shall not exceed 20 percent opacity except for one six-minute period per hour during which opacity shall not exceed 27 percent.
   [Rule 62-296.406(1), F.A.C.; and, applicant request dated July 20, 2000.]

5. Particulate Matter: Particulate Matter emissions shall be controlled by the firing of natural gas, as specified in the attached Appendix BD – BACT Determination.
[Rule 62-296.406(2), F.A.C.; and, BACT.]

6. Sulfur Dioxide: Sulfur Dioxide emissions shall be controlled by the firing of natural gas, as specified in the attached Appendix BD – BACT Determination.
[Rule 62-296.406(3), F.A.C.; and, BACT.]

7. Nitrogen Oxides: Nitrogen oxide emissions shall not exceed 0.10 lb/MMBtu, as measured by applicable compliance methods.
[Rule 62-4.070(3), F.A.C.; and, applicant request to avoid PSD applicability.]

EXCESS EMISSIONS

[Note: The following excess emissions provisions can not be used to vary any NSPS requirements (from any subpart of 40 CFR 60).]

8. Excess emissions resulting from start-up, shutdown or malfunction of any emissions units shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

9. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during start-up, shutdown, or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

REQUIRED TESTS

10. Visible Emissions: Prior to applying for a Title V operation permit revision, and annually thereafter, Unit -003 shall be tested for visible emissions, in accordance with the requirements listed below.
[Rule 62-297.320(7)(a)4., F.A.C.]

11. Nitrogen Oxides Emissions: Prior to applying for a Title V operation permit revision or renewal, Unit -003 shall be tested for nitrogen oxides emissions, in accordance with the requirements listed below.
[Rule 62-297.320(7)(a)4., F.A.C.]

TEST METHODS AND PROCEDURES

12. Visible Emissions: The test method for visible emissions shall be DEP Method 9 (see specific condition 13.), incorporated in Chapter 62-297, F.A.C.
[Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.]

13. DEP Method 9: The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
   (a) EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen-second intervals during the required period of observation.
   (b) EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 27 percent is permissible for not more than six minutes per hour) opacity shall be computed as follows:
      1. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
      2. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

      In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

   [Rule 62-297.401(9)(c), F.A.C.]

14. Nitrogen Oxides: The test method for Nitrogen oxide emissions shall be Method 7E, incorporated in Chapter 62-297, F.A.C.
   [Rule 62-297.401(7)(e), F.A.C.]

COMPLIANCE TEST REQUIREMENTS

15. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of

compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard.
[Rule 62-297.310(1), F.A.C.]

16. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C.]

17. Calculation of Emission Rate: The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

18. Applicable Test Procedures:
    (a) Required Sampling Time.
        1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
        2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
            a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
            b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
            c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

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TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

19. Determination of Process Variables:
   (a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
   (b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

   [Rule 62-297.310(5), F.A.C.]

20. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. Sampling facilities shall also conform to the requirements of attached Appendix SS.
   [Rule 62-297.310(6), F.A.C.]

21. Test Notification: The owner or operator shall notify the Department's district office and, if applicable, appropriate local program, at least 15 days prior to the date on which each formal compliance test is to begin. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
   [Rule 62-297.310(7)(a)9., F.A.C.; and, 40 CFR 60.8]

   [Note: The federal requirements of 40 CFR 60.8 require 30 days notice of the initial test and any tests required under section 114 of the Clean Air Act, but the Department rules require 15 days notice for the annual compliance tests. Unless otherwise advised by the district office or, if applicable, appropriate local program, provide 15 days notice prior to conducting annual tests, except for the initial test when 30 days notice is required.]

22. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the facility to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions units and to provide a report on the results of said tests to the Department.
   [Rule 62-297.310(7)(b), F.A.C.]

Reporting and Record Keeping Requirements

23. Duration of Record Keeping: 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. 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 five years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
[Rules 62-4.160(14)(a)&(b) and 62-213.440(1)(b)2.b., F.A.C.]

24. Test Reports:
   (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
   (b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
   (c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
      1. The type, location, and designation of the emissions unit tested.
      2. The facility at which the emissions unit is located.
      3. The owner or operator of the emissions unit.
      4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
      5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission-limiting standard.
      6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
      7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
      8. The date, starting time and duration of each sampling run.
      9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
      10. The number of points sampled and configuration and location of the sampling plane.
      11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
      12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

25. Excess Emissions Report: If excess emissions occur, the owner or operator shall notify the Department within one working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A.
[Rule 62-4.130, F.A.C.]

26. Excess Emissions Report - Malfunctions: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate local program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

27. Annual Operating Report for Air Pollutant Emitting Facility: The Annual Operating Report for Air Pollutant Emitting Facility shall be completed each year and shall be submitted to the Department's Southwest District office by March 1 of the following year.
[Rule 62-210.370(3), F.A.C.]

28. Notification Requirements:
(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by 40 CFR 60.7 (see attached Appendix A). This notification shall include:
(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(b) – (f) [Reserved]
(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.
(h) [Reserved]
(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of five years following the date of such record.
(j) [Reserved]
[62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 60.48c.]

29. Records of Hours of Operation. The owner or operator shall maintain an operation log available for Department inspection that documents the hours of operation each day. This record shall equal the hours that fuel is fired. Within 10 days after the end of each month, a record shall be made of the hours of operation in the previous consecutive 12-month period.
[Rules 62-4.070(3) & 62-210.200(PTE), F.A.C.]

30. Records of Heat Input. The owner or operator shall maintain an operation log available for Department inspection that documents the average hourly heat input (higher heating value) to the boiler, as follows. At the end of each 24-hour period that the boiler operates, the average hourly heat input shall be calculated and recorded utilizing the quantity of fuel combusted (see condition 28(g)), the actual hours operated in the previous 24-hour period (see condition 29.), and the representative heat content (higher heating value) of the as-fired fuel. The heat content of the fuel can be obtained from either on-site testing or from the fuel supplier, as long as the information provided is representative of the as-fired fuel.
[Rules 62-4.070(3) & 62-210.200(PTE), F.A.C.]

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[Note: The numbering of the original rules in the following conditions has been preserved for ease of reference to the rules. The term "Administrator" when used in 40 CFR 60 shall mean the Secretary or the Secretary's designee.]

1. Pursuant to 40 CFR 60.1 Applicability:
   (a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
   (b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
   (c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).

   [40 CFR 60.1]

2. Pursuant to 40 CFR 60.7 Notification And Record Keeping:
   (a) Any owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:
      (1) A notification of the date construction (or reconstruction as defined under 40 CFR 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
      (2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date.
      (3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.
      (4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
      (5) [Reserved]
      (6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for

the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7)[Reserved]

(b) The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) [Reserved]

(d) [Reserved]

(e) [Reserved]

(f) The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least three years following the date of such measurements, maintenance, reports, and records.

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[40 CFR 60.7]

3. <u>Pursuant to 40 CFR 60.8 Performance Tests</u>:

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance-testing facilities as follows: (1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures. (2) Safe sampling platform(s). (3) Safe access to sampling platform(s). (4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 CFR 60.8]

[See the note for specific condition 21 of Section II of this permit regarding the proper advance notification of compliance tests.]

4. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements:

(a) Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Reference Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected

facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) [Reserved]

(5) [Reserved]

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of paragraphs (a) through (e) of 40 CFR 60.11.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in 40 CFR 60, nothing in 40 CFR 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[40 CFR 60.11]

5. <u>Pursuant to 40 CFR 60.12 Circumvention</u>:
No owner or operator subject to the provisions of 40 CFR 60.12 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the

atmosphere.
[40 CFR 60.12]

6. Pursuant to 40 CFR 60.14 Modification:
   (a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.
   (b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:
      (1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.
      (2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.
   (c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.
   (d) [Reserved]
   (e) The following shall not, by themselves, be considered modifications under this part:
      (1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.
      (2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.
      (3) An increase in the hours of operation.
      (4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was

designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

[40 CFR 60.14]

7. Pursuant to 40 CFR 60.15 Reconstruction:

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost'" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.
(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:
(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 CFR 60.15]

8. <u>Pursuant to 40 CFR 60.19 General notification and reporting requirements</u>:

(a) For the purposes of 40 CFR 60, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of 40 CFR 60, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in 40 CFR 60 for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under 40 CFR 60 to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under 40 CFR 60, the owner or operator may change the dates by which periodic reports under 40 CFR 60 shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in 40 CFR 60. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) [Reserved]

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of 40 CFR 60.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in 40 CFR 60.

(2) Notwithstanding time periods or postmark deadlines specified in 40 CFR 60 for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[40 CFR 60.19]

This BACT determination is required for the source as set forth in the Rule 62-296.406, Florida Administrative Code (F.A.C.), Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources.

Description of Project:

The applicant is proposing to add a natural gas-fired package steam boiler to the facility. The purpose of this boiler is to provide a back-up supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons per year in order to avoid PSD applicability. Due to the use of natural gas fuel, the emissions of other pollutants will be quite low.

The construction permit application is being processed by the Tallahassee office. The application and BACT proposal was received in the Bureau of Air Regulation on May 17, 2000.

BACT Determination Requested by Applicant:

The applicant has proposed the use of up to 600 million cubic feet per year of natural gas as the only fuel for this unit in order to limit the potential increase of NO_X emissions to 30 tons per year.

BACT Determination by DEP:

Pursuant to Rule 62-296.406, F.A.C., particulate matter and sulfur dioxide emissions shall be limited by the use of the Best Available Control Technology (BACT). BACT is based on the maximum achievable reduction in emissions taking into consideration energy, environmental and economic impacts. BACT for the package boiler shall be the use of natural gas as the exclusive fuel. Natural gas shall be allowed up to 577 million standard cubic feet in any consecutive 12-month period. This is based on an assumed heat value of 1,040 Btu per standard cubic foot. Fuel oil shall not be fired in the package boiler and the owner or operator of the facility shall not connect a fuel oil supply to this boiler. Compliance with this limitation shall be verified by recording the monthly and rolling 12-month natural gas usage. The Department's compliance inspectors should verify that a fuel oil supply line is not provided to this unit.

BACT Determination Rationale:

Sulfur in fuel is a primary air pollution concern since most of the fuel sulfur becomes sulfur dioxide. Also, particulate matter emissions from fuel burning are related to the sulfur content. BACT for particulate matter and sulfur dioxide, the two pollutants regulated pursuant to Rule 62-296.406, F.A.C., is the use of a very low sulfur fuel such as natural gas. Burning of natural gas results in relatively lower emissions of other criteria pollutants as compared with firing fuel oil, with the exception of nitrogen oxides, which are higher. Carbon monoxide emissions appear to be slightly higher for natural gas until one accounts for the potential increase in CO emissions that would result from improper boiler operation or poor boiler maintenance while firing fuel oil. The emission factor for CO emissions from firing fuel oil must be adjusted upward by a factor of 10 to 100 to account for this possibility. Thus, for the majority of pollutants, including particulate matter and sulfur dioxide, the use of natural gas is the best alternative.

PSD Consideration:

DRAFT

Since the addition of the package boiler will increase the emissions of new and/or previously emitted pollutants (modification) at a facility that is already classified as a major facility, the proposed project must be evaluated for PSD applicability. Because this facility is considered a major facility for PSD, an evaluation of the applicability of PSD for the proposed package boiler must be made by comparing past actual emissions to future potential emissions, in terms of tons of emissions per year. For PSD to not apply to this project, the net increase in emissions must be below the PSD significance criteria for a major modification to a major facility. Past actual emissions are generally based on an average of the past two years of operating data for the existing source. Since the proposed package boiler will be an addition to the facility, past actual emissions are zero. Future potential emissions are based on the total potential annual fuel consumption.

Since the net increase for all pollutants is less than the PSD significance criteria, the addition of the package boiler is not subject to PSD. The limit on natural gas usage noted in the BACT Determination section above is required to ensure that the net emissions increase does not exceed the PSD significance criteria. This limit should be included in the construction permit and subsequent operation permits.

Details of the Analysis May be Obtained by Contacting:

Jonathan Holtom, P.E.
Department of Environmental Protection
Division of Air Resources Management
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850-921-9531

Recommended by: ______________________
C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Approved by: ______________________
Howard L. Rhodes, Director
Division of Air Resources Management

____
Date

____
Date

APPENDIX GC – GENERAL PERMIT CONDITIONS
[F.A.C. 62-4.160]

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

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey 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 or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

(c) Records of monitoring information shall include:

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

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

Stack Sampling Facilities Provided by the Owner of an Emissions Unit. This section describes the minimum requirements for stack sampling facilities that are necessary to sample point emissions units. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. Emissions units must provide these facilities at their expense. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.
2. The ports shall be capable of being sealed when not in use.
3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45-degree angle.
5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d) Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e) Access to Work Platform.

1. Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f) Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.
2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g) Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.
   a. The bracket shall be a standard 3-inch x 3-inch x one-quarter inch equal-legs bracket, which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.
   b. A three-eighth inch bolt, which protrudes 2 inches from the stack, may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.
   c. The three-quarter inch eyebolt shall be capable of supporting a 500-pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.
2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.
3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy

FROM: Jonathan Holtom

DATE: August 8, 2001

SUBJECT: Expiration Date Extension to Construction Permit for Tiger Bay Cogeneration Facility's Package Boiler (Permit Number 1050223-009-AC)

Attached for approval and signature is an expiration date extension to the construction permit for Florida Power Corporation's Tiger Bay Cogeneration Facility. This extension has been requested because the applicant inadvertently missed the deadline to submit a timely and complete application, which would have allowed continued operation pending the revision of the Title V permit.

The referenced project was for the installation of a natural gas-fired auxiliary package steam boiler in order to provide a backup supply of steam during periods of non-operation of the facility's combustion turbine. This steam will be used strictly to meet the requirements of a steam contract with the facility's property host. The maximum steam production capacity of 85,000 lb/hr corresponds to a maximum heat input capacity of 100 MMBtu/hr. Emissions of NO_X will be limited to 30 tons/year by imposition of an emissions limit of 0.1 lb/MMBtu and a limit of 6,000 hours per year.

The extension is needed in order to provide additional time to complete the Title V Air Operation Permit revision application, and to ensure the authority to operate the package boiler during the processing of the Title V revision. All required testing and report submittal have been completed.

I recommend your approval and signature.

Attachment

/jh

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 9, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger Zirkle, Plant Manager
Florida Power Corporation
P.O. Box 14042, MAC HE44
St. Petersburg, Florida 33733-4042

Re: Extension of Expiration Date of Permit No. 1050223-009-AC
Tiger Bay Cogeneration Facility

Dear Mr. Zirkle:

The Department has received your request for an extension of the expiration date of air construction permit number 1050223-009-AC, which was issued for the installation of a natural gas-fired auxiliary package steam boiler located at the Tiger Bay Cogeneration facility in Polk County. The Department has reviewed and agrees with this request. The expiration date is hereby extended from August 15, 2001 to February 15, 2002, to allow additional time for the submittal and processing of a Title V operating permit revision application.

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

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

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

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

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

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

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

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

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

This permitting decision 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 pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

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

Executed in Tallahassee, Florida.

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/10/01 to the person(s) listed:

Roger Zirkle, Plant Manager, FPC – Tiger Bay Cogeneration Facility*
Mr. J. Michael Kennedy, Florida Power Corporation
Mr. Bill Thomas, DEP, SWD

Clerk Stamp

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

Jonathan Holton 8/10/01
(Clerk) (Date)

AL
Scott

Florida Power
A Progress Energy Company

RECEIVED

AUG 03 2001

BUREAU OF AIR REGULATION

July 31, 2001

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

Dear Mr. Fancy:

Re: Tiger Bay Construction Permit Extension
1050223-009-AC

Florida Power is requesting a six (6) month extension to the above referenced permit. This request enables Florida Power to submit the additional information requested to ensure that the Title V application is complete. This would extend the construction permit expiration date to February 15, 2002.

Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

Roger B. Zirkle

Roger B. Zirkle
Plant Manager
Responsible Official

cc: Scott Sheplak, FDEP

bcc: J. A. Stenger
J. M. Kennedy

File: Tiger Bay Permit Applications

INTEROFFICE MEMORANDUM

Date: 20-Jul-2000 02:14pm
From: J-Michael.Kennedy
J-Michael.Kennedy@fpc.com
Dept:
Tel No:

Subject: Tiger Bay Package Boiler Permit

Jonathan,

Sorry I didn't get this to you sooner. As we discussed, FPC agrees to the following specifications in the Tiger Bay package boiler construction permit:

EPA Method 7E for NOx testing.

Opacity standard of 20% for normal operating conditions.

Up to 27% opacity allowed for one 6-minute period per hour.

I think that covers what we discussed. Feel free to call me with questions. Thank you.

Mike Kennedy
(727) 826-4334

Jonathan,

Sorry I didn't get this to you sooner. As we discussed, FPC agrees to the following specifications in the Tiger Bay package boiler construction permit:

EPA Method 7E for NOx testing.

Opacity standard of 20% for normal operating conditions.

Up to 27% opacity allowed for one 6-minute period per hour.

I think that covers what we discussed. Feel free to call me with questions. Thank you.

Mike Kennedy
(727) 826-4334

RFC-822-headers:
Received: from epic50.dep.state.fl.us ([199.73.169.50])
 by mail.epic1.dep.state.fl.us (PMDF V5.2-33 #37976)
 with ESMTP id <01JRZRAOCYXO001ETR@mail.epic1.dep.state.fl.us> for
 HOLTOM_J@a1.epic1.dep.state.fl.us (ORCPT rfc822;Holtom_J@dep.state.fl.us)
 ; Thu, 20 Jul 2000 14:14:19 EDT
Received: from msdmz01.fpc.com ([209.84.159.100])
 by mail.epic50.dep.state.fl.us (PMDF V5.2-32 #31508)
 with ESMTP id <01JRZR7OCU9Y0062K0@mail.epic50.dep.state.fl.us> for
 HOLTOM_J@a1.epic1.dep.state.fl.us (ORCPT rfc822;Holtom_J@dep.state.fl.us)
 ; Thu, 20 Jul 2000 14:11:54 -0400 (EDT)
Received: from sv003.fpc.com (msgoc01.fpc.com [148.152.8.60])
 by msdmz01.fpc.com (Pro-8.9.3/Pro-8.9.3) with ESMTP id OAA13194 for
 <Holtom_J@dep.state.fl.us>; Thu, 20 Jul 2000 14:11:12 -0400 (EDT)
Received: from localhost (root@localhost)
 by sv003.fpc.com (8.8.6 (PHNE_17135)/8.8.6) with SMTP id OAA12890 for
 Holtom_J@dep.state.fl.us; Thu, 20 Jul 2000 14:09:35 -0400 (EDT)
X-OpenMail-Hops: 1

Florida Power
CORPORATION

Date: 6/16/00

To: Jonathan Holton

FAX #: (850) 922-6979

Phone #: ( )

From: Mike Kennedy

FAX #: (727) 826-4216

Phone #: (727) 826-4334

4 Total number of pages including cover page.

Please notify ______ at (727) 826 - ______
for any problems concerning the receipt of this FAX.

Comments:

Nationwide Boiler Incorporated 42400 Christy Street Fremont, CA ...-7100 Fax 510-490-0571

Post-it® Fax Note 7671
To: EPC | Date: 2-17-00 | # of Pages: 17
Co./Dept: Carey Frost | From: Larry Day
Phone # | Co.: Nationwide Boiler
Fax # 941/519-6166 | Phone # | Fax #

February 17, 2000

Florida Power Corp.
263 – 13th Ave. South MAC BB2A
St. Petersburg, FL 33701

Attn: Carey Frost

Subject: RFP, FPC File No. : 00-013-CFF
Auxiliary Boiler – Tiger Bay

In response to your latest RFP, FPC File No. 11-013-CFF dated February 15, 2000, for an auxiliary boiler at Tiger Bay, we are pleased to present our **ALTERNATE BID** as follows:

A) Boiler

One (1) reconditioned 1990 85,000 lb/hr Cleaver-Brooks model DL-84 package watertube boiler, 260-psi design, natural gas fired, complete as follows:

New Coen Delta NOx low emission burner (0.10 lb/mmbtu NOx or less without FGR)
NFPA 8501 fuel train
New Coen Fyr Monitor PLC based boiler/burner control system self-contained in one (1) boiler mounted NEMA 4 panel with touch screen interface
New drum level transmitter with Fisher pneumatic control valve and 3 valve bypass
Rebuilt boiler trim and valving (safety valves, blowdown valves, stop/check & gate type header valves, vent valve, steam gauge, waterlevel gauge glass, LWCO, ALWCO, HWA)
FD Fan with 100 hp, 460 volt TEFC motor and starter
25' self-supporting stack with flanged boiler transition inlet

Connection Sizes:

Steam:	8" 300 psi flange
Gas:	3" 150 psi flange
Water:	2½ " 300 psi flange
Blowdown:	1 ¼" 300 flange

Dimensions:

Length:	35' 0"
Height:	14' 5¼"
Width:	11' 4½"
Shipping Weight:	96,800 pounds
Operating Weight:	131,300 pounds

B) Deaerator With Pumps:

One (1) reconditioned Cleaver-Brooks model SM140 Spray Type Package Deaerator, built 1992, .005 cc/liter oxygen guarantee, consisting of 84" x 15'4½" 50 psig ASME Coded receiver, stainless steel internals, 2,800 gallons storage capacity, normal tank trim items & pneumatic steam and water inlet control valves, structural steel stand, pump suction piping with strainers, three (3) new Paco model

OLN low NPSH 2-stage centrifugal pumps with 50 hp TEFC motors, new NEMA 4 control panel with lights, alarms, pump H-O-A switches and motor starters.

EQUIPMENT SALES TERMS AND CONDITIONS

Selling Price:	A) Boiler - $365,000 B) Deaerator with pumps - $65,000
Limited Warranty:	One (1) year per attached
Taxes:	Not Included
Installation:	Not Included
Air & Operating Permits:	Not Included
Expiration:	This quotation is valid for 90 days but availability is subject to prior rental or sale.
Terms of Payment:	25% with the order; balance upon delivery.
Freight:	*Allowed to jobsite nearest rail siding (unloaded by others)*
Start-up Service & Operator Training:	Included

UTILITY CUSTOMERS

Pacific Gas & Electric

Southern California Edison

Duke Power

Public Service Gas & Electric

Texas Utilities

Jacksonville Electric Authority

Sacramento Municipal Utility District

East Bay Municipal Utility District

Louisiana Power & Light

New York Power Authority

New York State Electric & Gas

Toledo Edison

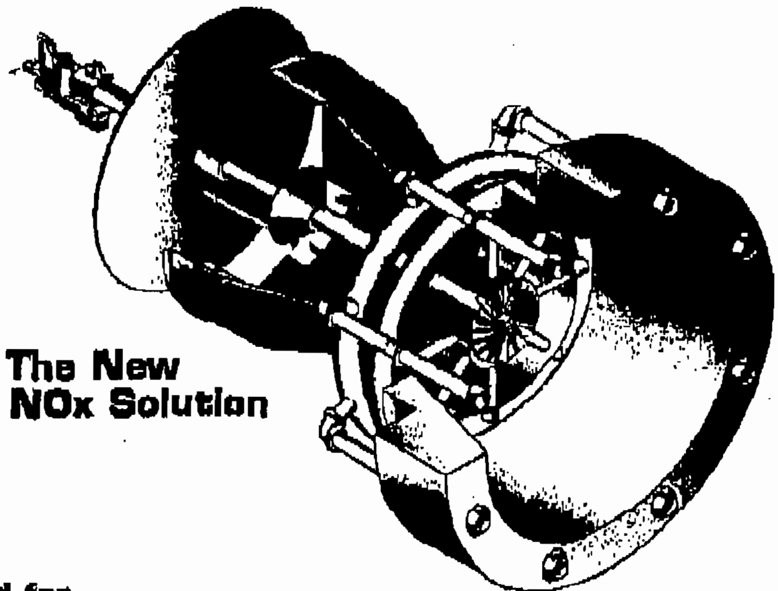
Nationwide Boiler Incorporated

42400 Christy Street, Fremont, CA 94538-4401 1-800-227-1966 510-490-7100 Fax: 510-490-0571

COEN

PRODUCT BULLETIN
Delta-NOx

THE DELTA-NOx BURNER



The New
Low NOx Solution

The New Standard for Packaged Boilers

The newest innovation in Coen's long legacy is the Delta-NOx burner, destined to be the new standard for the industrial and utility markets. The versatile Delta-NOx produces impressive performance results firing a variety of liquid and gaseous fuels. Firing natural gas, the Delta-NOx is designed to achieve 0.1 lbs/MMBtu NOx (83 ppm) without the addition of expensive flue gas recirculation (FGR) in high space heat release rate applications.

Coen's engineering team considered everything – from meeting coast to coast emission standards to designing a burner with simple construction and low cost. The result is a burner unlike any other in the industry.

The Delta-NOx utilizes Coen's new "Delta Spuds", which are unique gas injectors with a custom drilling pattern that controls ignition, and at the same time reduces formation of prompt and thermal NOx. The Delta Spuds, in combination with our custom low-swirl central stabilizer, achieve high burner turndown and low emissions. Additionally, the venturi style burner design provides superior air distribution with reduced pressure drop, further reducing NOx and CO emissions.

Design Features and Benefits

- < 0.1 lbs/MMBtu (83 ppm NOx) firing natural gas without FGR
- Lower NOx reductions with FGR (below 30 ppm)
- High space heat release applications
- Low gas pressures
- High burner turndown
- Low NOx capability with oil firing
- Safe operation with simple controls
- Compact flame
- Lower burner pressure and excess air (saves on horsepower costs)
- Uniform air distribution for low CO
- Simple, rugged design with no moving parts
- Easy installation and startup

Department of Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Florida Power Corporation		
2. Site Name : Tiger Bay Facility		
3. Facility Identification Number : 1050223		[ ] Unknown
4. Facility Location : Ft. Meade		
Street Address or Other Locator : 3219 State Road 630 East		
City : Ft. Meade	County : Polk	Zip Code : 33841
5. Relocatable Facility? [ ] Yes [X] No		6. Existing Permitted Facility? [X] Yes [ ] No

RECEIVED
MAY 17 2000
BUREAU OF AIR REGULATION

Owner/Authorized Representative or Responsible Official

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

Name : W. Jeffrey Pardue, C.E.P.
Title : Director, Environmental Services

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

Organization/Firm : Florida Power Corporation
Street Address : P.O. Box 14042, MAC BB1A
City : St. Petersburg
State : FL Zip Code : 33733

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

Telephone : (727)826-4301 Fax : (727)826-4216

4. Owner/Authorized Representative or Responsible Official Statement :

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

W. Pardue 5/15/00
Signature Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
004	Natural gas-fired package steam boiler	

Purpose of Application and Category

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

This Application for Air Permit is submitted to obtain :

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

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

Current construction permit number :

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

Operation permit to be renewed :

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

Current construction permit number :

Operation permit to be revised :

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

Operation permit to be revised/corrected :

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

Operation permit to be revised :

Reason for revision :

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

This Application for Air Permit is submitted to obtain :

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

Current operation/construction permit number(s) :

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

Operation permit to be renewed :

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

Operation permit to be revised :

Reason for revision :

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

This Application for Air Permit is submitted to obtain :

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

Current operation permit number(s), if any :
1050223-002-AV

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

Current operation permit number(s) :

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

Application Processing Fee

Check one :

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

Construction/Modification Information

1. Description of Proposed Project or Alterations : Addition of natural gas-fired package steam boiler for providing supplemental steam.	
2. Projected or Actual Date of Commencement of Construction :	01-Jul-2000
3. Projected Date of Completion of Construction :	30-Aug-2000

Professional Engineer Certification

1. Professional Engineer Name : Jennifer A. Stenger Registration Number : 0052125	
2. Professional Engineer Mailing Address : Organization/Firm : Florida Power Corporation Street Address : P.O. Box 14042, MAC BB1A City : St. Petersburg	State : FL Zip Code : 33733
3. Professional Engineer Telephone Numbers : Telephone : (727)826-4132	Fax : (727)826-4216

Application Contact

1. Name and Title of Application Contact : Name : J. Michael Kennedy, Q.E.P. Title : Manager, Air Programs
2. Application Contact Mailing Address : Organization/Firm : Florida Power Corporation Street Address : P.O. Box 14042, MAC BB1A City : St. Petersburg State : FL Zip Code : 33733
3. Application Contact Telephone Numbers : Telephone : (727)826-4334 Fax : (727)826-4216

Application Comment

This application is for the proposed addition of a natural gas-fired package steam boiler in order to provide a backup steam supply. The heat input capacity of the boiler is 100 mmBtu/hr, which subjects it to 40 CFR Part 60, Subpart Dc.

4. Professional Engineer Statement :

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

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

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

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

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

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

Jennifer A. Stenger — 5/15/00

Signature — Date

(seal)

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

* I am certifying the technical content of the permit application, but not the engineering design/construction of the supplemental steam boiler manufactured by Cleaver-Brooks.

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type 8

1. Facility UTM Coordinates : Zone : 17 East (km) : 416.20 North (km) : 3069.22			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 24 44 47 Longitude (DD/MM/SS) : 81 51 51			
3. Governmental Facility Code : 0	4. Facility Status Code : A	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) :
7. Facility Comment : Facility consists of a single combustion turbine (CT) that exhausts through a heat recovery steam generator (HRSG). The CT is permitted to burn natural gas or distillate fuel oil. The facility also operates a zero liquid discharge system that provides treatment of process wastewater and exhausts through a baghouse. Total capacity of the facility is 269.5 MW, of which a nominal 184 MW are from the CT and a nominal 85.5 MW are provided by the HRSG.			

Facility Contact

1. Name and Title of Facility Contact : Paul V. Crimi Asset Manager
2. Facility Contact Mailing Address : Organization/Firm : Florida Power Corporation Street Address : 3219 State Road 630 East City : Ft. Meade State : FL Zip Code : 33841
3. Facility Contact Telephone Numbers :

Telephone : (863)519-6101 Fax : (863)519-6110

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	N
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment : The CT is subject to NSPS for stationary gas turbines (40 CFR Part 60, Subpart GG).	

B. FACILITY REGULATIONS

Rule Applicability Analysis

Not Applicable

B. FACILITY REGULATIONS

List of Applicable Regulations

Refer to Attachment TB-F1-B

ATTACHMENT TB-F1-B

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	- NSPS Subpart GG
62-204.800(7)(c) (State Only)	- NSPS authority
62-204.800(7)(d)(State Only)	- NSPS General Provisions
62-204.800(12) (State Only)	- Acid Rain Program
62-204.800(13) (State Only)	- Allowances
62-204.800(14) (State Only)	- Acid Rain Program Monitoring
62-204.800(16) (State Only) permit)	- Excess Emissions (Potentially applicable over term of

Stationary Sources-General:

62-210.650	- Circumvention; EUs with control device
62-210.700(1)	- Excess Emissions;
62-210.700(4)	- Excess Emissions; poor maintenance
62-210.700(6)	- Excess Emissions; notification

Acid Rain:

62-214.300	- All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	- All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	- Compliance Options (if 214.430)
62-214.340	- Exemptions (new units, retired units)
62-214.350(2);(3);(6)	- All Acid Rain Units (Certification)
62-214.370	- All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	- All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	- CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	- All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	- All Units (Operating Rate; other than CTs;no CT)
62-297.310(3)	- All Units (Calculation of Emission)
62-297.310(4)(a)	- All Units (Applicable Test Procedures;Sampling time)
62-297.310(4)(b)	- All Units (Sample Volume)
62-297.310(4)(c)	- All Units (Required Flow Rate Range-PM/H2SO4/F)
62-297.310(4)(d)	- All Units (Calibration)
62-297.310(4)(e)	- All Units (EPA Method 5-only)
62-297.310(5)	- All Units (Determination of Process Variables)

62-297.310(6)(a)	- All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	- All Units (Sampling Ports)
62-297.310(6)(d)	- All Units (Work Platforms)
62-297.310(6)(e)	- All Units (Access)
62-297.310(6)(f)	- All Units (Electrical Power)
62-297.310(6)(g)	- All Units (Equipment Support)
62-297.310(7)(a)1.	- Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.a	- Annual Test
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	- PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS Subpart GG:	
40 CFR 60.332(a)(1)	- NOx for Electric Utility CTs
40 CFR 60.332(a)(3)	- NOx for Electric Utility CTs
40 CFR 60.333	- SO2 limits
40 CFR 60.334	- Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	- Test Methods

NSPS General Requirements:	
40 CFR 60.7(a)(1)	- Notification of Construction
40 CFR 60.7(a)(2)	- Notification of Initial Start-Up
40 CFR 60.7(a)(3)	- Notification of Actual Start-Up
40 CFR 60.7(a)(4)	- Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	- Notification of CEM Demonstration
40 CFR 60.7(b) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(c) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(d) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	- Performance Test Requirements
40 CFR 60.8(b)	- Performance Test Notification
40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Provide Stack Sampling Facilities
40 CFR 60.8(f)	- Test Runs
40 CFR 60.11(a)	- Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	- Compliance (opacity determined EPA Method 9)

40 CFR 60.11(c)	- Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	- Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	- Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	- Circumvention
40 CFR 60.13(a)	- Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c)	- Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	- Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	- Monitoring (COMS; span, system check)
40 CFR 60.13(e)	- Monitoring (frequency of operation)
40 CFR 60.13(f)	- Monitoring (frequency of operation)
40 CFR 60.13(h)	- Monitoring (COMS; data requirements)
Acid Rain-Permits:	
40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	- SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	- NOx Requirements
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners
40 CFR 72.24	- Certificate of representation
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(b)(2)	- Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.31	- Information Requirements; Acid Rain Applications
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification

Allowances:

40 CFR 73.33(a),(c)	- Authorized account representative
40 CFR 73.35(c)(1)	- Compliance: ID of allowances by serial number

Monitoring Part 75:

40 CFR 75.4	- Compliance Dates;
40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2;
40 CFR 75.10(a)(2)	- Primary Measurement; NOx;
40 CFR 75.10(a)(3)(iii)	- Primary Measurement; CO2; O2 monitor
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	- Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous firing
40 CFR 75.12(a)	- NOx Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(b)	- CO2 Monitoring; Appendix G
40 CFR 75.13(c)	- CO2 Monitoring; Appendix F
40 CFR 75.14(c)	- Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	- Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	- Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	- Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	- Recertification Backup/portable monitor
40 CFR 75.20(f)	- Alternate Monitoring system
40 CFR 75.21(a)	- QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	- QA/QC; Calibration Gases
40 CFR 75.21(d)	- QA/QC; Notification of RATA
40 CFR 75.21(e)	- QA/QC; Audits
40 CFR 75.21(f)	- QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	- Reference Methods
40 CFR 75.24	- Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	- General Missing Data Procedures; NOx
40 CFR 75.30(a)(4)	- General Missing Data Procedures; SO2
40 CFR 75.30(b)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	- General Missing Data Procedures; SO2 (optional before 1/1/97)
40 CFR 75.30(e)	- General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	- Initial Missing Data Procedures (new/re-certified CMS)

40 CFR 75.32	- Monitoring Data Availability for Missing Data
40 CFR 75.33	- Standard Missing Data Procedures
40 CFR 75.36	- Missing Data for Heat Input
40 CFR 75.40	- Alternate Monitoring Systems-General
40 CFR 75.41	- Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	- Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	- Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44	- Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	- Alternate Monitoring Systems-Daily QA
40 CFR 75.46	- Alternate Monitoring Systems-Missing data
40 CFR 75.47	- Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	- Alternate Monitoring Systems-Petition
40 CFR 75.53	- Monitoring Plan ; revisions
40 CFR 75.54(a)	- Recordkeeping-general
40 CFR 75.54(b)	- Recordkeeping-operating parameter
40 CFR 75.54(c)	- Recordkeeping-SO2
40 CFR 75.54(d)	- Recordkeeping-NOx
40 CFR 75.54(e)	- Recordkeeping-CO2
40 CFR 75.54(f)	- Recordkeeping-Opacity
40 CFR 75.55(c)	- General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	- General Recordkeeping (Specific Situations)
40 CFR 75.56	- Certification; QA/QC Provisions
40 CFR 75.60	- Reporting Requirements-General
40 CFR 75.61	- Reporting Requirements-Notification cert/recertification
40 CFR 75.62	- Reporting Requirements-Monitoring Plan
40 CFR 75.63	- Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	- Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	- Reporting Requirements-Quarterly reports; DR
statement	
40 CFR 75.64(c)	- Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	- Petitions to the Administrator (if required)
Appendix A-1	- Installation and Measurement Locations
Appendix A-2.	- Equipment Specifications
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix A-7.	- Calculations
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix D	- Optional SO2; Oil-/gas-fired units
Appendix F	- Conversion Procedures
Appendix H	- Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	- Offset Plans (future)

40 CFR 77.5(b)	- Deductions of Allowances (future)
40 CFR 77.6	- Excess Emissions Penalties (SO2 and NOx;future)

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
PM10	B
NOX	SM
PM	B
CO	B
SO2	B
VOC	B
SAM	B

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 1

1. Pollutant Emitted : PM10		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 2

1. Pollutant Emitted : NOX		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 3

1. Pollutant Emitted : PM		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 4

1. Pollutant Emitted : CO		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 5

1. Pollutant Emitted : SO2		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 6

1. Pollutant Emitted : VOC		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 7

1. Pollutant Emitted : SAM		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	TB-FE-1
2. Facility Plot Plan :	TB-FE-2
3. Process Flow Diagram(s) :	TB-FE-3
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	NA
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Applicat	TB-FE-4

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt
8. List of Equipment/Activities Regulated under
9. Alternative Methods of Operation :
10. Alternative Modes of Operation (Emissions
11. Identification of Additional Applicable
12. Compliance Assurance Monitoring
13. Risk Management Plan Verification :
14. Compliance Report and Plan :
15. Compliance Certification (Hard-copy Require

ATTACHMENT TB-FE-1

AREA MAP

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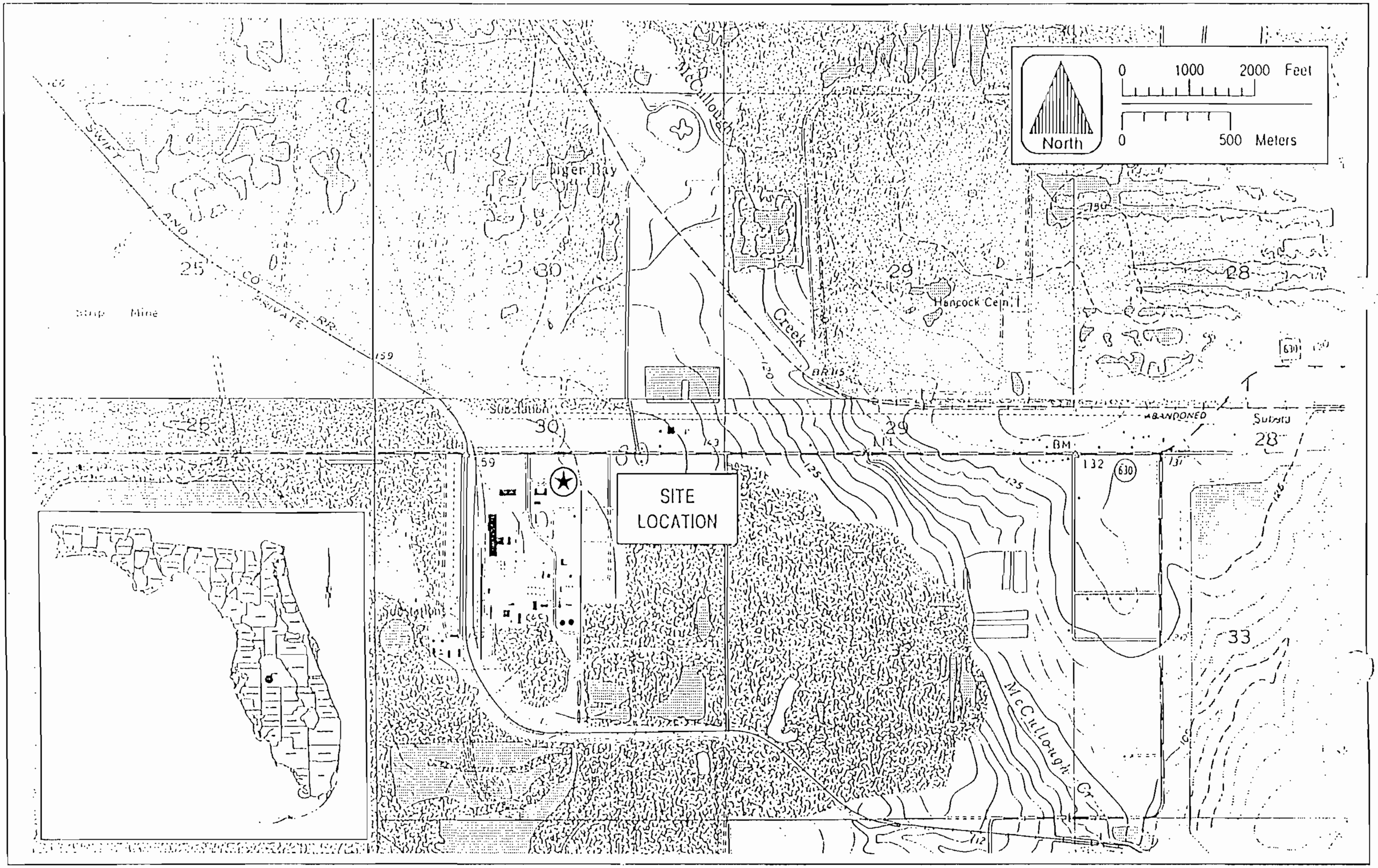
05 09 96



Attachment TB-FE-1
Tiger Bay Project Location Map

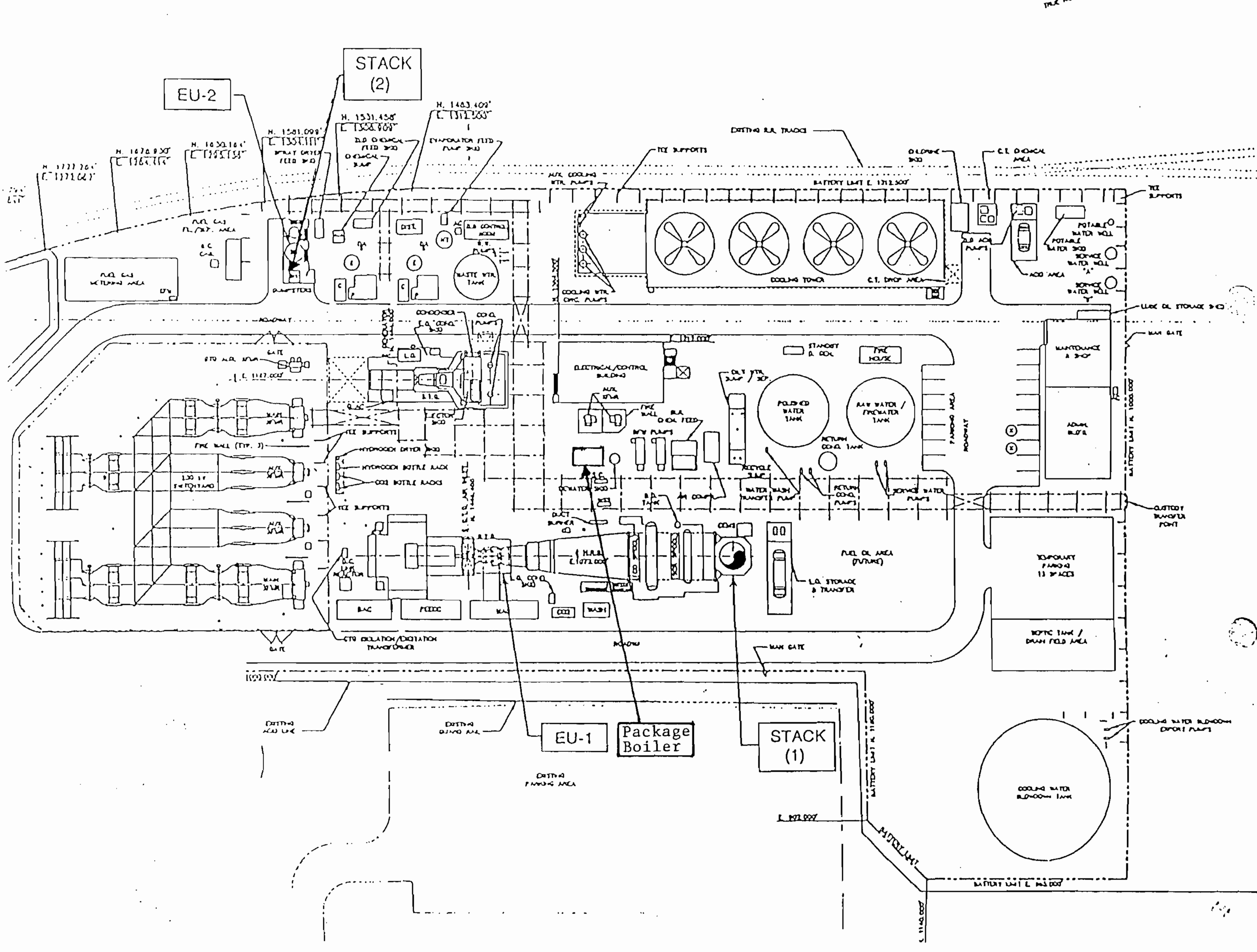
Sources: USGS, 1986, 1987; KBN, 1995.

KBN
A GOLDER ASSOCIATES COMPANY

ATTACHMENT TB-FE-2

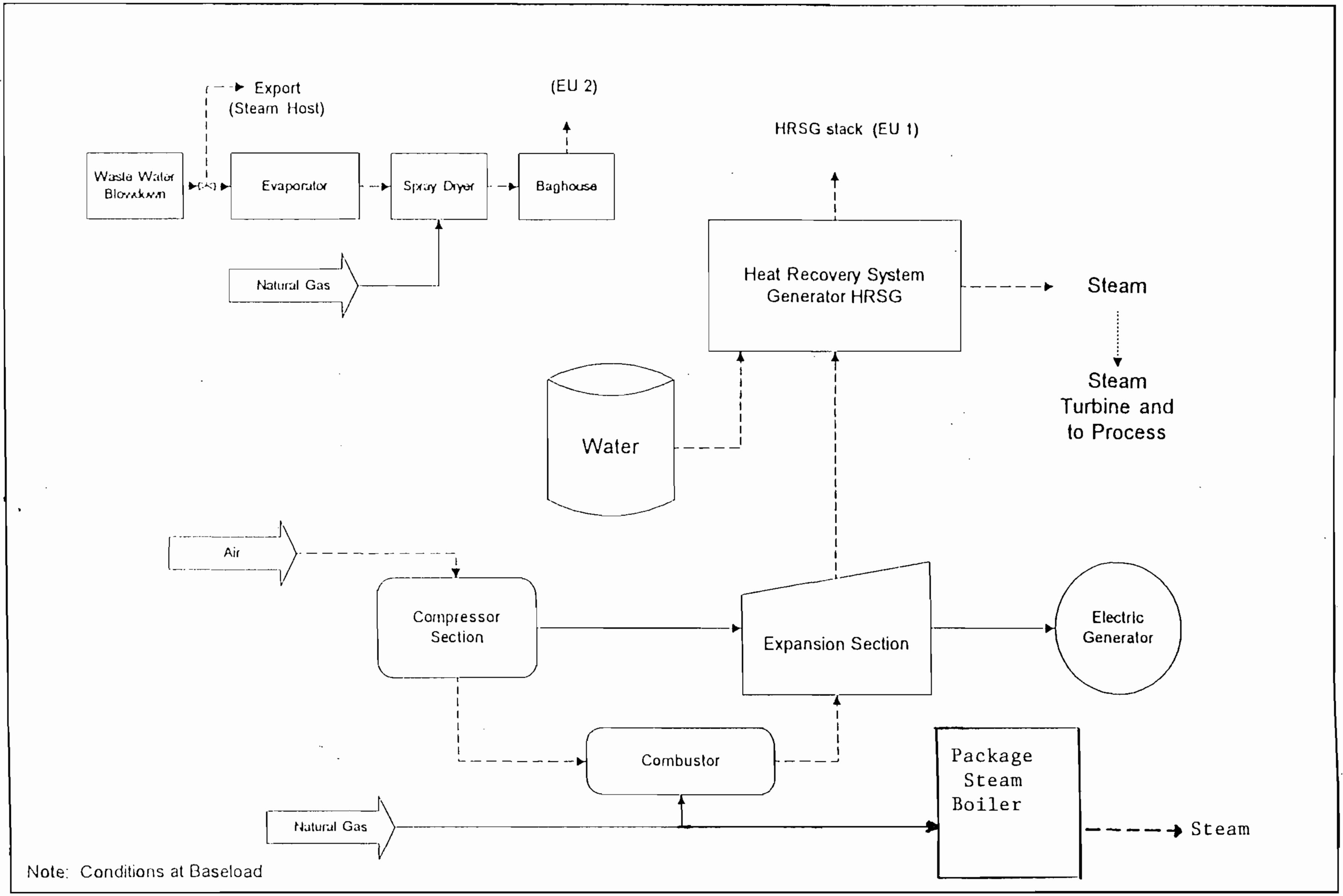
FACILITY PLOT PLAN

BEST AVAILABLE COPY



ATTACHMENT TB-FE-3

PROCESS FLOW DIAGRAM



ATTACHMENT: TB-FE-3

Flow Diagram of Facility
Process Area: Tiger Bay

Process Flow Legend
- Solid/Liquid ———▸
- Gas – – – –▸
- Steam ··········▸

Emission Unit:

Filename: TBCOGEN.VSD

Date: 06/10/96

KBN Engineering and Applied Sciences, Inc.

ATTACHMENT TB-FE-4

SUPPLEMENTAL INFORMATION

Description of Project and Operation Limit

The proposed package boiler installation will provide supplemental steam to the facility. The boiler will be natural gas-fired only with a maximum steam production capacity of 85,000 lb/hour, which corresponds to a heat input capacity of 100 mmBtu/hour. Emissions of NOx will be limited to a maximum increase of 39.9 tons/year. Due to the use of natural gas fuel, the emissions of all other pollutants will be quite low.

Florida Power Corporation (FPC) requests that the operational limit of the unit placed in the permit be in terms of annual hours of operation. At an emission rate of 0.10 lb/mmBtu, and using the rated heat input capacity of 100 mmBtu/hour, the boiler will emit a maximum of 10 lb/hour of NOx. Limiting the maximum annual increase of NOx at the facility will allow the boiler to operate a total of 7,980 hours/year at capacity. FPC will maintain records of the hours of operation of the boiler.

ATTACHMENT TB-FE-5

TYPICAL FUEL ANALYSIS

BEST AVAILABLE COPY

FGT SYSTEM CHROMATOGRAPHS

Spot Analysis of Natural Gas for Delivery in Florida

Date	Time
4/10/00	1:21 PM

	Perry	Perry	Brooker	Gainsville	West Palm	
	36" Stream #1	30" Stream #2	24" Stream	8" Stream	24" Stream	
	Mole%	Mole%	Mole%	Mole%	Mole%	
Components						
Hexane	**0.0564**	**0.0572**	**0.0468**	**0.0544**	**0.0551**	
Propane	**0.4222**	**0.4248**	**0.3214**	**0.3692**	**0.4281**	
Iso-Butane	**0.0959**	**0.0966**	**0.0708**	**0.0827**	**0.0968**	
N-Butane	**0.0965**	**0.0966**	**0.0715**	**0.0818**	**0.0961**	
Iso-Pentane	**0.0303**	**0.0299**	**0.0200**	**0.0207**	**0.0287**	
N-Pentane	**0.0200**	**0.0190**	**0.0118**	**0.0134**	**0.0187**	
Nitrogen	**0.4146**	**0.4143**	**0.3013**	**0.3701**	**0.3865**	
Methane	**95.2614**	**95.2441**	**96.6236**	**96.0097**	**95.6535**	
C02	**0.7902**	**0.7936**	**0.6947**	**0.7638**	**0.6985**	
Ethane	**2.8125**	**2.8239**	**1.8382**	**2.2343**	**2.5380**	
Totals	**100.0000**	**100.0000**	**100.0000**	**100.0000**	**100.0000**	
Btu	**1027.7**	**1038.4**	**1029.3**	**1032.6**	**1037.4**	Dry Btu/cf @ 14.
Gravity	**0.5786**	**0.5874**	**0.5788**	**0.5827**	**0.5849**	Real Relative De
Total Sulfur	**5.5954**	**3.9392**	**2.8022**			PPM
	0.3497	**0.2462**	**0.1751**			Grains/hcf
Current H2O	**3.5764**		**1.5677**		**1.6575**	Lbs. Per MMcf

$$576.92 \frac{MMCF}{Yr} \times \frac{0.35\ gr}{100\ cf} \times \frac{1\ lb}{7000\ gr} \times \frac{1\ ton}{2000\ lb} = 0.14\ TPY\ SO_2$$

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 1

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Natural gas-fired package steam boiler		
2. Emissions Unit Identification Number : 004 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : A	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment :		

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Emissions Unit Control Equipment 1

1. Description :	
2. Control Device or Method Code :	

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Emissions Unit Details

1. Initial Startup Date :		
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : Cleaver-Brooks		Model Number : DL-94
4. Generator Nameplate Rating :	MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	100	mmBtu/hr	
2. Maximum Incinerator Rate :		lb/hr	tons/day
3. Maximum Process or Throughput Rate :			
4. Maximum Production Rate :	85000	lbs steam/hr	
5. Operating Capacity Comment : Heat input capacity is 100 mmBtu/hr. Steam generating capacity is 85,000 lb/hr.			

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :		
	24 hours/day	7 days/week
	52 weeks/year	7,980 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Rule Applicability Analysis

Not Applicable

List of Applicable Regulations

62-204.8 Excess Emissions
62-210.700 Excess Emissions
62-297.310 Emission Monitoring

40 CFR 60.40c

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	See Attach. TB-FE-2	
2. Emission Point Type Code :	1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : Gases exhaust through a single stack.		
5. Discharge Type Code :	V	
6. Stack Height :	40	feet
7. Exit Diameter :	4.0	feet
8. Exit Temperature :	320	°F
9. Actual Volumetric Flow Rate :	29162	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 0 East (km) : 0.000 North (km) : 0.000		

14. Emission Point Comment :

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Nat gas

Natural gas-fired package steam boiler

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Natural gas	
2. Source Classification Code (SCC) : ~~20100201~~ – Internal Combustion Turbine 10200602	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 0.10	5. Maximum Annual Rate : 798.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash : 0.00
9. Million Btu per SCC Unit : 1,040	
10. Segment Comment :	

$$\frac{100 \frac{MMBtu}{hr}}{1040 \frac{Btu}{CF}} = 96,153.85 \frac{CF}{hr} \times 6000 \frac{hrs}{Yr} = 576.92 \frac{MM\,CF}{Yr}$$

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO_2			EL
2 - NOX			EL
3 - PM			EL
4 - PM10			EL
5 - CO			EL
6 - VOC			EL
7 - SAM			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **SO2**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 0.1400000 lb/hour 0.5600000 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor 1 Units : gr/100 CF Reference : Fuel analysis
7. Emissions Method Code : 2
8. Calculations of Emissions : Assumed max. S content of 1 gr/100 CF and 7980 hours of operation/year.
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **NOX**
2. Total Percent Efficiency of Control : 0.00 %
3. Potential Emissions : 10.0000000 lb/hour 39.9000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor 0.10 Units : lb/mmBtu Reference : Manufacturer data
7. Emissions Method Code : 0
8. Calculations of Emissions : NOx emissions of 0.10 lb/mmBtu from manufacturer data. Annual max. tons of NOx from max. heat input of 100 mmBtu/hr and 7980 hours/year operation. 39.9 TPY NOx x 2000 lb/Ton = 79800 lb NOx/Yr ÷ 10 lb/hr = 7,980 hrs/yr.
9. Pollutant Potential/Estimated Emissions Comment : @ 80% => 6384 hrs. x 10 lb/hr = 31.92 TPY

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.8000000 lb/hour	3.1900000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 8 Reference : AP-42, nat. gas fire	Units : lb/mmCF
7. Emissions Method Code : 3	
8. Calculations of Emissions : AP-42 factor for PM (assume all PM is PM10) of 8 lb/mmCF and boiler capacity of 0.10 mmCF/hour. Annual emissions based on hourly rate times 7,980 hours/year.	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **CO**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 8.4000000 lb/hour	33.5000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 84 Reference : AP-42	Units : lb/mmCF
7. Emissions Method Code : 3	
8. Calculations of Emissions : AP-42 factor of 84 lb/mmCF and max. nat. gas firing capacity of 0.10 mmCF/hr. Annual emissions from hourly rate times 7,980 hours/year.	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **VOC**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.6000000 lb/hour	2.3900000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 6 Reference : AP-42	Units : lb/mmCF
7. Emissions Method Code : 3	
8. Calculations of Emissions : AP-42 factor of 6 lb/mmCF and max. nat. gas firing capacity of 0.10 mmCF/hr. Annual emissions from hourly rate times 7,980 hours/year.	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		1.00		grain S/100 CF
4. Equivalent Allowable Emissions :	0.14	lb/hour	0.56	tons/year
5. Method of Compliance : Fuel analysis				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable based on max. sulfur content of 1 gr/100 CF of natural gas.				

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	ESCPSD			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.10	lb/mmBtu		
4. Equivalent Allowable Emissions :	10.00	lb/hour	39.90	tons/year
5. Method of Compliance : Stack test, EPA Method 20				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Based on emission rate of 0.10 lb/mmBtu and 7980 hours/year.				

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.80	lb/hr		
4. Equivalent Allowable Emissions :	0.80	lb/hour	3.19	tons/year
5. Method of Compliance : VE, EPA Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : If VE < 10%, stack test not required.				

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	8.40	lb/hr		
4. Equivalent Allowable Emissions :	8.40	lb/hour	33.50	tons/year
5. Method of Compliance : Good combustion practices				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :				

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.60	lb/hr		
4. Equivalent Allowable Emissions :	0.60	lb/hour	2.39	tons/year
5. Method of Compliance : Good combustion practices				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :	10		
2. Basis for Allowable Opacity :	OTHER		
3. Requested Allowable Opacity :			
Normal Conditions :		10	%
Exceptional Conditions :		0	%
Maximum Period of Excess Opacity Allowed :			min/hour
4. Method of Compliance :			
Annual compliance test, EPA Method 9			
5. Visible Emissions Comment :			
VE limit under normal conditions at full load.			

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Natural gas-fired package steam boiler

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :			
2. Basis for Allowable Opacity : RULE			
3. Requested Allowable Opacity :			
	Normal Conditions :		%
	Exceptional Conditions :	100	%
	Maximum Period of Excess Opacity Allowed :	60	min/hour
4. Method of Compliance : EPA Method 9			
5. Visible Emissions Comment : 1. Rule 62-210.700. 2. Max. period of excess opacity allowed - 2 hours/24 hours.			

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section __1__
Natural gas-fired package steam boiler

Continuous Monitoring System Continuous Monitor __1__

1. Parameter Code :	2. Pollutant(s):
3. CMS Requirement :	
4. Monitor Information Manufacturer : Model Number : Serial Number :	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment :	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[X] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[X] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Natural gas-fired package steam boiler

Supplemental Requirements for All Applications

1. Process Flow Diagram :	TB-FE-3
2. Fuel Analysis or Specification :	TB-FE-5
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	TB-FE-4
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

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P 062 921 956

Receipt for Certified Mail

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(See Reverse)

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Return Receipt Showing to Whom & Date Delivered	
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TOTAL Postage & Fees	$
Postmark or Date 1-15-93 AC 53-214903 PSD-Fl-190	

PS Form 3800, June 1991

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1. ☐ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
Robert D. Taylor
Central Fl Power, LP
500 City West Blvd - Suite 150
Houston, TX 77042

4. Type of Service:	Article Number
☐ Registered ☐ Insured ☒ Certified ☐ COD ☐ Express Mail	P 062 921 956

Always obtain signature of addressee or agent and **DATE DELIVERED.**

5. Signature – Addressee

6. Signature – Agent
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7. Date of Delivery
1-19-93

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

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 15, 1993

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Robert I. Taylor, Project Manager
Central Florida Power, Limited Partnership
2500 City West Blvd., Suite 150
Houston, Texas 77042

Dear Mr. Taylor:

Attached is one copy of the Technical Evaluation and Preliminary Determination and proposed permit to construct a 258 MW cogeneration facility located 5 miles west of Ft. Meade, Florida.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. Preston Lewis of the Bureau of Air Regulation.

Sincerely,

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

CHF/TH/plm

Attachments

cc: Kennard F. Kosky, P.E.
Bill Thomas, SWD
Jewell Harper, EPA
John Bunyak, NPS
Linda Novak, Polk Co.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DER File No. **AC**53-214903
PSD-FL-190
Polk County

Central Florida Power, Limited Partnership
2500 City West Blvd., Suite 150
Houston, Texas 77042

______________________________________/

INTENT TO ISSUE

The Department of Environmental Regulation gives notice of its intent to issue a permit (copy 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, Central Florida Power, Limited Partnership, applied on June 15, 1992, to the Department of Environmental Regulation for a permit to construct a 258 MW cogeneration facility. The facility is located 5 miles west of Ft. Meade, Polk County, Florida.

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 Permit. 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 permit.

The Department will issue the permit 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 REGULATION

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 1-15-93 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.

Clerk 1-15-93
Date

Copies furnished to:
- Kennard F. Kosky, P.E.
- Bill Thomas, SWD
- Jewell Harper, EPA
- John Bunyak, NPS
- Linda Novak, Polk Co.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Regulation gives notice of its intent to issue a PSD permit to Central Florida Power, Limited Partnership (CFPLP), County Road 630, 5 miles west of Ft. Meade, Polk County, Florida, to construct a 258 MW cogeneration facility. A determination of Best Available Control Technology (BACT) was required. The Department is issuing this Intent to Issue for the reasons 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 Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Department of Environmental Regulation
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's Tallahassee address. 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

Central Florida Power, Limited Partnership
Ft. Meade, Polk County, Florida

258 MW Cogeneration Facility

Permit Number: AC53-214903
PSD-FL-190

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

January 15, 1993

SYNOPSIS OF APPLICATION

I. NAME AND ADDRESS OF APPLICANT

Central Florida Power, Limited Partnership
2500 City West Blvd., Suite 150
Houston, Texas 77042

II. REVIEWING AND PROCESS SCHEDULE

Date of Receipt of Application: June 15, 1992.

Completeness Review: Department letters dated July 14 and October 9, 1992.

Response to Incompleteness Letters: Company letters received on August 26, October 9, and October 23, 1992.

Application Completeness Date: October 9, 1992.

III. FACILITY INFORMATION

III.1 **Facility Location**

This facility is located near Ft. Meade, Polk County, Florida. The UTM coordinates are Zone 17, 416.22 km East and 3069.22 km North.

III.2 **Facility Identification Code (SIC)**

Major Group No. 49 - Electric, Gas and Sanitary Services.

Industry Group No. 491 - Combination Electric, Gas and Other Utility Services.

Industry Group No. 4911 - Electric and Other Services Combined.

III.3 **Facility Category**

Central Florida Power, L.P.'s (CFPLP) proposed project near Ft. Meade is classified as a major emitting facility. The proposed project, a 258 MW cogeneration facility , will increase emissions by 702 tons per year (TPY) of nitrogen oxides (NO_x); 33 TPY of sulfur dioxide (SO_2); 243 TPY of carbon monoxide (CO); 45 TPY of particulate matter (PM); 25 TPY of volatile organic compounds

(VOC); 0.000616 TPY of beryllium; 0.00219 TPY of lead; 0.000739 TPY of mercury; and 4.05 TPY of sulfuric acid mist if the combustion turbine is operated at 8,460 hours per year on natural gas, duct burner operated at 8,760 hours per year on natural gas, and the combustion turbine is operated at 300 hours per year on fuel oil (0.05% S) at base load and at 72°F.

IV. PROJECT DESCRIPTION

CFPLP proposes to operate a 258 MW cogeneration facility consisting of one 184 MW combustion turbine generator (CT), one 74 MW steam turbine generator (ST), and one duct burner-fired heat recovery steam generator (HRSG) and ancillary equipment.

The CT will be a GE PG7221FA machine. The CT will be served by a single HRSG, exhausting to an individual stack. There will be no bypass stacks on the CT for simple cycle operation. There will be two electrical generators, which will be individually driven by the CT and the steam turbine. Natural gas will be the primary fuel, maximum 8,760 hours per year, for the cogeneration facility over its lifetime; distillate fuel oil (0.05% S) will be used as a backup fuel for up to 3,742,327 gallons per calendar year. Supplementary firing of only natural gas will occur in the HRSG.

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. NO_x emissions will be minimized by using dry low-NO_x technology for the CT and low-NO_x burners when duct firing. The use of natural gas will minimize the emissions of sulfur dioxide (SO_2) and other pollutants.

V. RULE APPLICABILITY

The proposed project is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, Chapters 17-212 and 17-4, Florida Administrative Code (F.A.C.), and 40 CFR (July, 1992 version).

This facility is located in an area designated attainment for all criteria pollutants in accordance with F.A.C. Rule 17-275.400.

The proposed project will be reviewed under F.A.C. Rule 17-212.400(5), New Source Review (NSR) for Prevention of Significant Deterioration (PSD), because it will be a major new stationary source. This review consists of a determination of Best Available Control Technology (BACT) and unless otherwise exempted, an analysis of the air quality impact of the increased emissions. The review also includes an analysis of the project's impacts on soils, vegetation and visibility; along with air quality impacts resulting from associated commercial, residential and industrial growth.

The proposed facility shall be in compliance with all applicable provisions of F.A.C. Chapters 17-212 and 17-4 and the 40 CFR 60 (July, 1992 version). The proposed source shall be in compliance with all applicable provisions of F.A.C. Rules 17-210.650: Circumvention; 17-210.700: Excess Emissions; 17-296.800: Standards of Performance for New Stationary Sources (NSPS); 17-296: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

The proposed facility shall be in compliance with the New Source Performance Standards (NSPS) for Gas Turbines, Subpart GG and NSPS for Industrial Steam Generating Units, Subpart Dc, which are contained in 40 CFR 60, Appendix A, and are adopted by reference in F.A.C. Rule 17-296.800.

The proposed Tiger Bay cogeneration project is less than 75 MW (steam cycle portion) and is therefore exempt from the provisions of the Florida Electrical Power Plant Siting Act.

VI. SOURCE IMPACT ANALYSIS

VI.1 **Emission Limitations**

The operation of this cogeneration facility burning distillate fuel oil and natural gas will produce emissions of NO_x, SO_2, CO, VOC, sulfuric acid mist, PM, PM_{10}, As, Fluorides, Be, Pb and Hg. The impact of these pollutant emissions are below the Florida ambient air quality standards (AAQS) and/or the acceptable ambient concentration levels (AAC). Table 1 lists each contaminant and its maximum expected emission rates for the 258 MW cogeneration facility.

VI.2 **Air Toxics Evaluation**

The operation of the sources will produce emissions of chemical compounds that may be toxic in high concentrations. The emission rates of these chemicals shall not create ambient concentrations greater than the No-Threat-Level (NTL) listed in the Department's air toxic list. This project as proposed is in compliance with the Department's air toxic guidelines.

VI.3 **Air Quality Analysis**

a. Introduction

The operation of the proposed facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: NO_x, PM,

PM_{10}, Be, CO, and inorganic arsenic. Therefore, the project is subject to the PSD NSR requirements contained in F.A.C. Rule 17-2.500(5) for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;
- A PSD increment analysis (for PM, PM_{10}, and NO_x);
- An Ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and,
- A Good Engineering Practice (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD (NSR) is given below:

	TSP & PM10	NO_x	CO	Be
PSD de minimus Concentra. (ug/m^3)	10	14	575	0.001
Averaging Time	24-hr	Annual	8-hr	24-hr
Maximum Predicted Impact (ug/m^3)	2.12	0.29	20.8	.00021

There are no monitoring de minumus concentrations for inorganic arsenic. As shown above, the predicted impacts are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for these pollutants.

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Tampa Florida National Weather Service (NWS) station collected during 1982 through 1986 were used in the model. Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations are compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for criteria pollutants CO, NO_2, PM and PM_{10}. This evaluation was based on the proposed facility operating at load conditions of 100% and 70% and 27°F and 97°F. In addition, the modeling was performed based on the lowest exit velocity and highest emission rate of the two combustion turbine models, Westinghouse and GE, for each load and temperature. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed units at the following downwind distances: (1) the first 36 receptors were located at the plant property boundaries; (2) subsequent receptors were located at distances of 0.1, 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 3.0, 4.0 and 5.0 km from the facility. Both screening and refined modeling was done. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for CO, NO_2, PM and PM_{10}.

	NO2	CO		PM and PM_{10}	
Avg. Time	Annual	1-hr	8-hr	Ann.	24-hr
PSD Signifi. Level (ug/m^3)	1.0	2000	500	1.0	5.0
Ambient Concen. Increase (ug/m^3)	0.29	45.8	20.8	0.022	2.12

Therefore, further dispersion modeling for comparison with AAQS and PSD Class II increment consumption were not required for these pollutants.

Beryllium and inorganic arsenic are noncriteria pollutants, which means that neither national AAQS nor PSD Significant Impacts have been defined for these pollutants. However, the Department does have a draft Air Toxics Permitting Strategy, which defines no threat levels for these pollutants. The Department and the applicant have used the same modeling procedure described above to evaluate the maximum ground level concentrations of these pollutants for comparison with the no-threat levels. The results of this analysis are shown below:

	Be			As		
Avg. Time	Annual	24-hr	8-hr	Annual	24-hr	8-hr
No Threat-Level (ug/m^3)	0.00042	.0048	0.02	0.00023	0.48	2
Max. Concen.	0.000007	.00021	0.00048	0.000011	0.00036	0.00081

All of these values are less than their respective no-threat levels. Other applicable air toxics are also less than their respective no-threat levels.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area located about 120 km northwest of the facility. The predicted impact of PM and NO_2 emissions from the proposed project on this area was evaluated by first using the ISCST2 model to predict maximum increment consumptions by the source alone and by comparing these predicted values to the appropriate recommended significance levels to determine whether further modeling was necessary. The significance levels used by the Department were the more stringent National Park Service (NPS) recommended levels. The predicted maximum NO_2 and PM increment consumptions for all applicable averaging times were less than these significance levels. Therefore, no further modeling for these time periods was required.

e. Additional Impacts Analysis

A Level-1 screening analysis using the EPA model, VISCREEN was used to determine any potential adverse visibility impacts on the Class I Chassahowitzka National Wilderness Area located about 120km away. Based on this analysis, the maximum predicted visual impacts due to the proposed project are less than the screening criteria both inside and outside the Class I area. A comprehensive air quality related values (AQRV) analysis for this Class I area was performed by the applicant. No significant impacts on the Class I area are expected.

In addition, the maximum predicted concentrations from NOx, CO, PM and PM_{10} are predicted to be less than the AAQS, including the national secondary standards designed to protect public welfare-related values. As such, no harmful effects on soil and vegetation are expected in the area of the project. Also, the proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

VII. CONCLUSION

Based on the information provided by CFPLP, the Department has reasonable assurance that the proposed installation of the 258 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 Chapter 17-212 of the Florida Administrative Code.

#41755

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor — Carol M. Browner, Secretary

PERMITTEE:
Central Florida Power, L.P.
2500 City West Blvd., Ste. 150
Houston, Texas 77042

Permit Number: AC53-214903
PSD-FL-190
Expiration Date: January 1, 1996
County: Polk
Latitude/Longitude: 27°44'46.7"N
81°51'0.3"W
Project: A 258 MW Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 275, 296, 297 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 or on file with the Department and made a part hereof and specifically described as follows:

Central Florida Power, Limited Partnership, proposes to operate a 258 MW cogeneration facility consisting of one combustion turbine generator, one steam turbine generator, one duct burner-fired heat recovery steam generator and ancillary equipment. This facility is located near Ft. Meade, Polk County, Florida. The UTM coordinates are Zone 17, 416.22 km East and 3069.22 km North.

The 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.

Attachments are listed below:

1. Central Florida Power, Limited Partnership's (CFPLP) application received on June 15, 1992.
2. Department's letters dated July 14 and October 9, 1992.
3. CFPLP's letters received on August 26, October 9, and October 23, 1992.

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 17-30.300, 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;

GENERAL CONDITIONS:

- 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:

Emission Limits

1. The maximum allowable emissions from this source shall not exceed the emission rates listed in Table 1.

2. Visible emissions for full load operation shall not exceed 10% opacity when firing natural gas and 20% opacity when firing distillate fuel oil.

Operating Rates

3. This source is allowed to operate continuously (8,760 hours per year).

4. This source is allowed to use natural gas as the primary fuel for 8,760 hours per year and low sulfur distillate fuel oil (0.05% S) as the secondary fuel up to 3,742,327 gallons per calendar year.

5. The permitted materials and utilization rates for the combined cycle gas turbine system shall be as stated in the application. The operating parameters include, but are not limited to:

184 MW Combustion Turbine
74 MW Steam Turbine

a) The maximum heat input of 1,849.9 MMBtu/hr (LHV) at 27°F and at base load for distillate fuel oil.

b) The maximum heat input of 1,614.8 MMBtu/hr (LHV) at 27°F and at base load for natural gas.

SPECIFIC CONDITIONS:

Duct Burner

c) The maximum heat input of 100 MMBtu/hr (HHV) of natural gas.

6. Any change in the method of operation, equipment or operating hours pursuant to Rule 17-212.200, F.A.C., Definitions-Modifications, shall be submitted to DER's Bureau of Air Regulation and Southwest District offices.

7. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

Compliance Determination

8. Compliance with the NO_x, SO_2, CO, PM, PM_{10}, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1992 version) and adopted by reference in F.A.C. Rule 17-297.

- Method 1 — Sample and Velocity Traverses for Stationary Sources
- Method 2 — Determination of Stack Gas Velocity and Volumetric Flow Rate
- Method 3 — Gas Analysis
- Method 5 — Determination of Particulate Emissions from Stationary Sources
  or
  Method 17 — Determination of Particulate Emissions from Stationary Sources
- Method 18 — Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
- Method 9 — Visual Determination of the Opacity of Emissions from Stationary Sources
- Method 8 — Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
- Method 10 — Determination of Carbon Monoxide Emission from Stationary Sources
- Method 20 — Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
- Method 25A — Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

SPECIFIC CONDITIONS:

- Method 201A and Method 201	Determination of PM_{10} Emissions from Stationary Sources
- Method 12 or Method 101A	Determination of Lead Concentrations from Stationary Sources
- Method 8	Determination of PM and Gaseous Arsenic Emissions from Stationary Sources

Other DER approved methods may be used for compliance testing after prior Departmental approval.

9. Method 5 or Method 17 or Method 201A and Method 201 must be performed to determine the initial compliance status of particulate matter emissions of the unit. Thereafter, the opacity emissions test, Method 9, may be used unless the applicable opacity is exceeded. Also, the ambient particulate matter entering the gas turbine can be subtracted from the total particulate matter emissions if that quantity can be measured at the inlet of the gas turbine.

10. Compliance with the SO_2 and sulfuric acid mist emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuel.

11. Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

12. Mercury (Hg) shall be tested during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

13. During performance tests, to determine compliance with the proposed NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\ obs}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19}\ (H_{obs} - 0.00633)\ \left(\frac{288°K}{T_{AMB}}\right)^{1.53}$$

where:

SPECIFIC CONDITIONS:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x\ obs}$ = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

14. Test results will be the average of 3 valid runs. The Southwest District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources, combustion turbine and duct burner, shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). Compliance test results shall be submitted to the Southwest District office no later than 45 days after completion.

15. The permittee shall leave sufficient space in the heat recovery steam generator suitable for future installation of SCR equipment should the facility be unable to meet the NO_x standards, if required.

16. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992).

17. A continuous monitoring system shall be installed to monitor and record the fuel consumption on the CT and duct burner. While water/steam injection is being utilized for NO_x control, the water/steam to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

SPECIFIC CONDITIONS:

18. Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be determined as specified in 40 CFR 60.334(b). Any request for a future custom monitoring schedule shall be made in writing and directed to the Southwest District office. Any custom schedule approved by DER pursuant to 40 CFR 60.334(b) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of distillate fuel oil usage shall be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight.

Rule Requirements

19. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-210, 212, 275, 296, 297 and 17-4, Florida Administrative Code and 40 CFR 60 (July, 1992 version).

20. The sources shall comply with all requirements of 40 CFR 60, Subpart GG and Subpart Dc, and F.A.C. Rule 17-296.800,(2)(a), Standards of Performance for Stationary Gas Turbines and Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

21. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-210.300(1)).

22. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-210.650: Circumvention; 17-210.700: Excess Emissions; 17-296.800: Standards of Performance for New Stationary Sources (NSPS); 17-297: Stationary Sources-Emissions Monitoring; and, 17-4.130: Plant Operation-Problems.

23. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which contruction has not commenced (40 CFR 52.21(r)(2)).

24. Quarterly excess emission reports, in accordance with the July 1, 1992 version of 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office.

SPECIFIC CONDITIONS:

25. Fugitive dust emissions, during the construction period, shall be minimized by covering or watering dust generation areas.

26. 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 emissions limits, etc. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

27. 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).

28. 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).

Issued this ______ day
of _______________, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Carol M. Browner
Secretary

CENTRAL FLORIDA POWER, L.P. - AC53-214903 (PSD-FL-190)
258 MW COMBINED CYCLE GAS TURBINE

Table 1 - Allowable Emission Rates

Pollutant	Fuel[A]	Allowable Emission[C] Standard/Limitation	Basis
NO_x (CT)	Gas	15 ppmvd @ 15% O_2 (97.2 lbs/hr; 425.7 TPY)[B]	BACT
	Gas	25 ppmvd @ 15% O_2 (161.9 lbs/hr; 709.1 TPY)	BACT
	Oil	42 ppmvd @ 15% O_2 (326 lbs/hr; 48.9 TPY)	BACT
NO_x (DB)	Gas	0.1 lbs/MMBtu (10 lbs/hr, 43.8 TPY)	BACT
CO (CT)	Gas	15 ppmvd (48.8 lbs/hr; 213.7 TPY)[D]	BACT
	Oil	30 ppmvd (98 lbs/hr; 14.8 TPY)	BACT
CO (DB)	Gas	10 lbs/hr; 43.8 TPY	BACT
VOC (CT)	Gas	2.8 lbs/hr; 12.3 TPY	BACT
	Oil	7.5 lbs/hr; 1.1 TPY	BACT
VOC (DB)	Gas	2.9 lbs/hr; 12.7 TPY	BACT
PM_{10} (CT)	Gas	0.0100 lbs/MMBtu	BACT
	Oil	0.0100 lbs/MMBtu	BACT
PM_{10} (DB)	Gas	0.0100 lbs/MMBtu	BACT
SO_2 (CT)	Gas	4.86 lbs/hr; 21.3 TPY	Appl.
	Oil	99.7 lbs/hr; 15.0 TPY	Appl.
SO_2 (DB)	Gas	0.3 lbs/hr; 1.32 TPY	Appl.
H_2SO_4 (CT)	Gas	5.9×10^{-1} lbs/hr; 2.6 TPY	Appl.
	Oil	1.2 lbs/hr; 0.18 TPY	Appl.
H_2SO_4 (DB)	Gas	3.7×10^{-2}; 1.6×10^{-1}	Appl.
Opacity	Gas	10% opacity[D]	BACT
	Oil	20% opacity	BACT
Hg	Oil	3.0×10^{-12} lb/MMBtu	Appl.
As	Oil	4.2×10^{-12} lb/MMBtu	BACT
Be	Oil	2.0×10^{-12} lb/MMBtu	BACT
Pb	Oil	8.9×10^{-12} lb/MMBtu	Appl.

A) Fuel: <u>Natural Gas</u>: Emissions are based on 8760 hours per year operating time.
Fuel: <u>No. 2 Distillate Fuel Oil (0.05% S)</u>: Emissions are based on fuel usage equivalent to 300 hours per year at maximum capacity (i.e., 3,742,327 gallons per year).

B) The NO_x maximum limit will be lowered to 15 ppmv @ 15% O_2 by 12/31/97 using appropriate combustion technology improvements or SCR.

C) Emission rates are based on 27°F at base load.

D) At full load conditions.

Best Available Control Technology (BACT) Determination
Central Florida Power, L.P.
Polk County
PSD-FL-190

The applicant proposes to construct a cogeneration facility near Ft. Meade, Polk County. This generator system will consist of a 184 MW General Electric PG7221FA combustion turbine generator (CT), equipped with a duct burner-fired heat recovery steam generator (HRSG), which will be used to power a nominal 74 MW steam turbine generator (ST).

The applicant has requested to burn natural gas for 8760 hours per year and distillate fuel oil, with a 0.05 percent sulfur content for a maximum 3,742,327 gallons per year. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility at base load, 27°F and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Gas PG7221FA (8460 hrs)	Gas Duct Burner (8760 hrs)	Oil PG7221FA (300 hrs)	Total	PSD Significant Emission Rate (TPY)
NO_x	684.7	43.8	48.9	777.4	40
SO_2	20.5	1.3	15	36.8	40
PM/PM_{10}	38.1	4.4	2.6	45.1	25/15
CO	206.5	43.8	14.8	265.1	100
VOC	11.80	12.7	1.1	25.6	40
H_2SO_4	2.5	0.16	1.9	4.5	7
Be	nil	nil	6.94×10^{-4}	6.94×10^{-4}	0.0004
Hg	nil	nil	8.32×10^{-4}	8.32×10^{-4}	0.1
Pb	nil	nil	2.47×10^{-4}	2.47×10^{-4}	0.6
As	nil	nil	1.17×10^{-3}	1.17×10^{-3}	0

Florida Administrative Code (F.A.C.) Rule 17-212.400(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

<u>Date of Receipt of a BACT Application</u>

June 15, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) Control Technology: Dry Low-NO_x Burners when firing natural gas and steam/water injection when firing distillate oil
SO_2	0.05% sulfur by weight (fuel oil firing)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

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, than the

next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

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

- Combustion Products (e.g., particulates). 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.

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

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not exceed 0.01 lb/MMBtu. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

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

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

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

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed combined cycle turbine is on exhaust concentrations of 15 ppmv for natural gas firing and 30 ppmv for fuel oil firing.

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

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

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst are not considered to be technically feasible for gas turbines fired with fuel oil.

Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for natural gas-fired unit; however, the cost effectiveness of $10,000 per ton for the PG7221FA of CO removed will have an economic impact on this project.

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

ACID GASES

Nitrogen Oxides (NO_x)

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

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

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

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

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

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

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

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 (spend catalyst).
d) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
e) The energy impacts of SCR will reduce potential electrical power generation of more than 7 million kwh per year.
f) Incremental cost effectiveness for the application of SCR technology to the Central Florida Power project was considered to be $7,400 per ton of NO_x removed.

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

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

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

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

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

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

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $3,364,400 for the PG7221FA. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For this project, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using dry low-NO_x (natural gas) and water injection (oil firing) will be 702.1 tons/year (at 72°F). Assuming that SCR would reduce the NO_x emissions by 65%, about 245.7 TPY would be emitted annually. When this reduction (456.4 TPY) is taken into consideration with the total levelized annual operating cost of $3,364,400; the cost per ton of controlling NO_x is $7,400. This calculated cost is higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will likely be available by

1997, the Department has accepted the water/steam injection (for distillate fuel oil firing), the dry low-NO_x burner design, and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 12/31/97).

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for this turbine [$7,400 per ton (natural gas)] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water/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 General Electric is developing programs for the PG7221FA using either steam/water injection or dry low NO_x combustor technology to achieve a NO_x emission control level of 15 ppm when firing natural gas. Therefore, 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 12/31/97.

CO Control

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

Other Emissions Control

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

The emission limits for the Central Florida Power, L.P. project are thereby established as follows:

258 MW COMBINED CYCLE COMBUSTION TURBINE
100 MMBtu/hr Duct Burner

Pollutant	Emission Standards/Limitations[a] Oil[b]	Gas[c]	Method of Control
NO_x (CT)	42 ppmv at 15% O_2	25 ppmv[d] at 15% O_2 15 ppmv at 15% O_2	Water Injection/ Dry Low-NO_x Combustor Dry Low-NO_x Combustor or any other NO_x Control Technology
NO_x (DB)		0.1 lbs/MMBtu	
CO (CT)	98 lbs/hr	49 lbs/hr	Combustion
CO (DB)		10 lbs/hr	
PM/PM_{10} (CT)	17 lbs/hr	9 lbs/hr	Combustion
PM/PM_{10} (DB)		0.01 lbs/MMBtu	
SO_2 (CT)	99.7 lbs/hr	4.9 lbs/hr	Distillate Fuel Oil (0.05% S)
SO_2 (DB)		0.3 lbs/hr	
H_2SO_4 (CT)	1.2 lbs/hr	5.9×10^{-1} lbs/hr	Distillate Fuel Oil (0.05% S)
H_2SO_4 (DB)		3.7×10^{-2} lbs/hr	
VOC (CT)	7.5 lbs/hr	2.8 lbs/hr	Combustion
VOC (DB)		2.9 lbs/hr	
Hg	3.0×10^{-12} lbs/MMBtu		Fuel Quality
Pb	8.9×10^{-12} lbs/MMBtu		Fuel Quality
Be	2.5×10^{-12} lbs/MMBtu		Fuel Quality
As	$4.2 \times 10{-}^{12}$ lbs/MMBtu		Fuel Quality

(a) Emissions calculated at base load and 27°F.
(b) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.
(c) Natural gas (8460 hours per year), Fuel oil (300 hours per year).
(d) Initial NO_x emission rates for natural gas firing shall not

exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_X emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_X combustor injection technology or any other combustion technology, but no later than 12/31/97.

<u>Details of the Analysis May be Obtained by Contacting</u>:

Preston Lewis, BACT Coordinator
Department of Environmental Regulation
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	Carol M. Browner, Secretary Dept. of Environmental Regulation
____________________ 1993 Date	____________________ 1993 Date

Kofax

Separator

PSD

P 230 524 300

Receipt for Certified Mail

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Sent to Mr. Robert I. Taylor, Centra FL Power	
Street and No. 2500 City West Blvd. Ste 150	
P.O., State and ZIP Code Houston, TX 77042	
Postage	$
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Return Receipt Showing to Whom & Date Delivered	
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TOTAL Postage & Fees	$

Postmark or Date
Mailed: 5-17-93
Permit: AC 53-214903
PSD-FL-190

PS Form 3800, June 1991

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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.
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I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
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Consult postmaster for fee.

3. Article Addressed to:
Mr. Robert I. Taylor
Project Manager
Central Florida Power, L.P.
2500 City West Blvd., Suite 150
Houston, TX 77042

4a. Article Number
P 230 524 300

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

7. Date of Delivery
5-20-93

5. Signature (Addressee)

6. Signature (Agent)

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

Thank you for using Return Receipt Service.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permits by:

Mr. Robert I. Taylor, Project Manager
Central Florida Power, L.P.
2500 City West Blvd., Suite 150
Houston, Texas 77042

DER File No. AC53-214903
PSD-FL-190
Polk County

_______________________________________/

Enclosed is Permit Number AC 53-214903 for Central Florida Power, L.P. to consruct a 258 MW cogeneration facility in Ft. Meade, Polk County, Florida. This permit is issued pursuant to Section(s) 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 REGULATION

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 5-17-93 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.

(Clerk) 5-17-93 (Date)

Copies furnished to:

B. Thomas, SW District
K. Kosky, P.E., KBN
J. Harper, EPA
J. Bunyak, NPS
L. Novak, Polk County

Final Determination

Central Florida Power, Limited Partnership
Ft. Meade, Polk County, Florida

258 MW Cogeneration Facility

Permit Number: AC53-214903
PSD-FL-190

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

May 6, 1993

Final Determination

The Technical Evaluation and Preliminary Determination for the permit to construct a 258 cogeneration facility at Central Florida Power, Limited Partnership (CFPLP), in Ft. Meade, Polk County, Florida, was distributed on January 15, 1993. The Notice of Intent to Issue was published in The Polk County Democrat on February 4, 1993. Copies of the evaluation were available for public inspection at the Department's offices in Tampa and Tallahassee.

CFPLP's application for a permit to construct a 258 MW cogeneration facility has been reviewed by the Bureau of Air Regulation in Tallahassee. No adverse comments were submitted by the U.S. Environmental Protection Agency (EPA) in their letter dated February 16, 1993, or by the U.S. Department of the Interior (Fish and Wildlife Services) in their letter of February 5, 1993.

Comments regarding the Technical Evaluation and Preliminary Determination (Sypnosis of Application) and Permit Specific Conditions were submitted by Kennard F. Kosky, P.E., President of KBN Engineering and Applied Sciences, Inc. The Bureau has considered Mr. Kosky's comments and agreed to the changes proposed in the wording and adjustment of numerical limits to reflect manufacturer's specifications since these changes will not affect the potential emissions considered during the evaluation of this project. The amendments to the Specific Conditions of the permit are as follows:

RESPONSE TO COMMENTS NOS. 1, 2, 3, 4, AND 5

These changes will be incorporated in Table 1.

RESPONSE TO COMMENTS NOS. 5 AND 6

The table on page 9 of the BACT determination and Table 1 of the permit (Specific Condition No. 1) will be amended to reflect these comments.

BACT DETERMINATION BY DER (PAGE 8)

This paragraph will be added to the NO_x control section: For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of this permit pursuant to F.A.C. Rule 17-4.080, Modification of Permit Conditions.

RESPONSE TO ITEM NO. 2 ON KBN'S LETTER OF JANUARY 30, 1993

Information given to DER and to the U.S. Department of Interior (Fish and Wildlife Services) indicates that General Electric's goal is to attempt a NO_x level of 9 ppmvd when firing natural gas.

<u>IN RESPONSE TO THE U.S. DEPARTMENT OF INTERIOR, SPECIFIC CONDITION NO. 15 WILL BE CHANGED AS FOLLOWS</u>:

FROM: The permittee shall leave sufficient space in the heat recovery steam generator suitable for future installation of SCR equipment should the facility be unable to meet the NO_x standards, if required.

TO: The permittee shall comply with the following by 12/31/97:

a) For this turbine, if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 12/31/97, SCR or other control technology will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.

<u>IN RESPONSE TO THE MARCH 11, 1993, LETTER FROM KENNARD F. KOSKY, KBN</u>

The Department has determined the following:

<u>Mandating SCR</u>: The Department is giving the permittee the flexibility to incorporate any design feature to meet the 15 (gas) ppmvd at 15% O_2 NO_x emission limit. SCR or other control technology shall be installed if the 15 (gas) ppmvd cannot be met by 12/31/97.

<u>Lowering the permit/BACT limit for NO_x</u>: The Department may revise the permitted emission level for NO_x. For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of this permit, pursuant to F.A.C. Rule 17-4.080, Modification of Permit Conditions.

<u>SPECIFIC CONDITION NO. 14 WILL BE MODIFIED AS FOLLOWS. THE PARAGRAPH IN BOLD WAS INADVERTENTLY OMITTED IN THE DRAFT PERMIT</u>

Specific Condition No. 14: Test results will be the average of 3 valid runs. The Southwest District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources, combustion turbine and duct burner, shall operate between 95% to 100% of the maximum capacity for the ambient conditions experienced during compliance test(s). **The turbine manufacturer's capacity vs temperature (ambient) curve shall be included with the compliance test results.** Compliance test results shall be submitted to the Southwest District office no later than 45 days after completion.

The final action of the Department will be to issue construction permit AC53-214903 (PSD-FL-190) with the changes noted above.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Virginia B. Wetherell, Secretary

PERMITTEE:
Central Florida Power, L.P.
2500 City West Blvd., Ste. 150
Houston, Texas 77042

Permit Number: AC53-214903
PSD-FL-190
Expiration Date: January 1, 1996
County: Polk
Latitude/Longitude: 27°44'46.7"N
81°51'0.3"W
Project: A 258 MW Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-210, 212, 275, 296, 297 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 or on file with the Department and made a part hereof and specifically described as follows:

Central Florida Power, Limited Partnership, proposes to operate a 258 MW cogeneration facility consisting of one combustion turbine generator, one steam turbine generator, one duct burner-fired heat recovery steam generator and ancillary equipment. This facility is located near Ft. Meade, Polk County, Florida. The UTM coordinates are Zone 17, 416.22 km East and 3069.22 km North.

The 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.

Attachments are listed below:

1. Central Florida Power, Limited Partnership's (CFPLP) application received on June 15, 1992.
2. Department's letters dated July 14 and October 9, 1992.
3. CFPLP's letters received on August 26, October 9, and October 23, 1992.

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 17-30.300, 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;

GENERAL CONDITIONS:

- 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:

Emission Limits

1. The maximum allowable emissions from this source shall not exceed the emission rates listed in Table 1.

2. Visible emissions for full load operation shall not exceed 10% opacity when firing natural gas and 20% opacity when firing distillate fuel oil.

Operating Rates

3. This source is allowed to operate continuously (8,760 hours per year).

4. This source is allowed to use natural gas as the primary fuel for 8,760 hours per year and low sulfur distillate fuel oil (0.05% S) as the secondary fuel up to 3,742,327 gallons per calendar year.

5. The permitted materials and utilization rates for the combined cycle gas turbine system shall be as stated in the application. The operating parameters include, but are not limited to:

184 MW Combustion Turbine

a) The maximum heat input of 1,849.9 MMBtu/hr (LHV) at 27°F and at base load for distillate fuel oil.

b) The maximum heat input of 1,614.8 MMBtu/hr (LHV) at 27°F and at base load for natural gas.

SPECIFIC CONDITIONS:

Duct Burner

c) The maximum heat input of 100 MMBtu/hr (HHV) of natural gas.

6. Any change in the method of operation, equipment or operating hours pursuant to Rule 17-212.200, F.A.C., Definitions-Modifications, shall be submitted to DER's Bureau of Air Regulation and Southwest District offices.

7. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

Compliance Determination

8. Compliance with the NO_X, SO_2, CO, PM, PM_{10}, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1992 version) and adopted by reference in F.A.C. Rule 17-297.

- Method 1 Sample and Velocity Traverses for Stationary Sources
- Method 2 Determination of Stack Gas Velocity and Volumetric Flow Rate
- Method 3 Gas Analysis
- Method 5 Determination of Particulate Emissions from Stationary Sources
  or
  Method 17 Determination of Particulate Emissions from Stationary Sources
- Method 18 Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
- Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources
- Method 8 Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
- Method 10 Determination of Carbon Monoxide Emission from Stationary Sources
- Method 20 Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
- Method 25A Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

SPECIFIC CONDITIONS:

- Method 201A Determination of PM_{10} Emissions from Stationary Sources
  and
  Method 202 Determination of Condensible Particulate Emissions from Stationary Sources

Other DER approved methods may be used for compliance testing after prior Departmental approval.

9. Method 5 or Method 17 or Method 201A and Method 202 must be performed to determine the initial compliance status of particulate matter emissions of the unit. Thereafter, the opacity emissions test, Method 9, may be used unless the applicable opacity is exceeded. Also, the ambient particulate matter entering the gas turbine can be subtracted from the total particulate matter emissions if that quantity can be measured at the inlet of the gas turbine.

10. Compliance with the SO_2 and sulfuric acid mist emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuel.

11. Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

12. Mercury (Hg) shall be tested during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

13. During performance tests, to determine compliance with the NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\ obs}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19\ (H_{obs} - 0.00633)} \left(\frac{288°K}{T_{AMB}}\right)^{1.53}$$

where:

SPECIFIC CONDITIONS:

NO_X = Emissions of NO_X at 15 percent oxygen and ISO standard ambient conditions.

$NO_{X\ obs}$ = Measured NO_X emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

14. Test results will be the average of 3 valid runs. The Southwest District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources, combustion turbine and duct burner, shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's capacity vs temperature (ambient) curve shall be included with the compliance test results. Compliance test results shall be submitted to the Southwest District office no later than 45 days after completion.

15. The permittee shall comply with the following by 12/31/97:

   a) For this turbine, if the 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2 emission rates cannot be met by 12/31/97, SCR or other control technology will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.

16. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992).

17. A continuous monitoring system shall be installed to monitor and record the fuel consumption on the CT and duct burner. While water/steam injection is being utilized for NO_X control, the water/steam to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

SPECIFIC CONDITIONS:

18. Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be determined as specified in 40 CFR 60.334(b). Any request for a future custom monitoring schedule shall be made in writing and directed to the Southwest District office. Any custom schedule approved by DER pursuant to 40 CFR 60.334(b) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of distillate fuel oil usage shall be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight.

Rule Requirements

19. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-210, 212, 275, 296, 297 and 17-4, Florida Administrative Code and 40 CFR 60 (July, 1992 version).

20. The sources shall comply with all requirements of 40 CFR 60, Subpart GG and Subpart Dc, and F.A.C. Rule 17-296.800,(2)(a), Standards of Performance for Stationary Gas Turbines and Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

21. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-210.300(1)).

22. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-210.650: Circumvention; 17-210.700: Excess Emissions; 17-296.800: Standards of Performance for New Stationary Sources (NSPS); 17-297: Stationary Sources-Emissions Monitoring; and, 17-4.130: Plant Operation-Problems.

23. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from the Department a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which contruction has not commenced (40 CFR 52.21(r)(2)).

24. Quarterly excess emission reports, in accordance with the July 1, 1992 version of 40 CFR 60.7 and 60.334 shall be submitted to the Department's Southwest District office.

PERMITTEE:
Central Florida Power, L.P.

Permit Number: AC53-214903
PSD-FL-190
Expiration Date: January 1, 1996

SPECIFIC CONDITIONS:

25. Fugitive dust emissions, during the construction period, shall be minimized by covering or watering dust generation areas.

26. 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 emissions limits, etc. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

27. 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).

28. 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).

Issued this 17th day
of May, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Virginia B. Wetherell

Virginia B. Wetherell
Secretary

CENTRAL FLORIDA POWER, L.P. - AC53-214903 (PSD-FL-190)
258 MW COMBINED CYCLE GAS TURBINE

Table 1 - Allowable Emission Rates

Pollutant	Fuel[A]	Allowable Emission[C] Standard/Limitation	Basis
NO_x (CT)	Gas	15 ppmvd @ 15% O_2 (97.2 lbs/hr; 425.7 TPY)[B]	BACT
	Gas	25 ppmvd @ 15% O_2 (161.9 lbs/hr; 709.1 TPY)	BACT
	Oil	42 ppmvd @ 15% O_2 (326 lbs/hr; 48.9 TPY)	BACT
NO_x (DB)	Gas	0.1 lbs/MMBtu (10 lbs/hr, 43.8 TPY)	BACT
CO (CT)	Gas	15 ppmvd (48.8 lbs/hr; 213.7 TPY)[D]	BACT
	Oil	30 ppmvd (98.4 lbs/hr; 14.8 TPY)	BACT
CO (DB)	Gas	10 lbs/hr; 43.8 TPY	BACT
VOC (CT)	Gas	2.8 lbs/hr; 12.3 TPY	BACT
	Oil	7.5 lbs/hr; 1.1 TPY	BACT
VOC (DB)	Gas	2.9 lbs/hr; 12.7 TPY	BACT
PM_{10} (CT)	Gas	9 lbs/hr; 39.4 TPY	BACT
	Oil	17 lbs/hr; 2.6 TPY	BACT
PM_{10} (DB)	Gas	0.0100 lbs/MMBtu	BACT
SO_2 (CT)	Gas	4.86 lbs/hr; 21.3 TPY	Appl.
	Oil	99.7 lbs/hr; 15.0 TPY	Appl.
SO_2 (DB)	Gas	0.3 lbs/hr; 1.32 TPY	Appl.
H_2SO_4 (CT)	Gas	5.95×10^{-1} lbs/hr; 2.6 TPY	Appl.
	Oil	1.22 lbs/hr; 0.183 TPY	Appl.
H_2SO_4 (DB)	Gas	3.7×10^{-2} lbs/hr; 1.61×10^{-1} TPY	Appl.
Opacity	Gas	10% opacity[D]	BACT
	Oil	20% opacity[D]	BACT
Hg	Oil	3.0×10^{-6} lbs/MMBtu (5.55×10^{-3} lbs/hr; 8.32×10^{-4} TPY)	Appl.
As	Oil	4.2×10^{-6} lbs/MMBtu (7.77×10^{-3} lbs/hr; 1.17×10^{-3} TPY)	BACT
Be	Oil	2.5×10^{-6} lbs/MMBtu (4.62×10^{-3} lbs/hr; 6.94×10^{-4} TPY)	BACT
Pb	Oil	8.9×10^{-6} lbs/MMBtu (1.65×10^{-2} lbs/hr; 2.47×10^{-3} TPY)	Appl.

A) Fuel: <u>Natural Gas</u>: Emissions are based on 8760 hours per year operating time.
Fuel: <u>Distillate Fuel Oil (0.05% S)</u>: Emissions are based on fuel usage equivalent to 300 hours per year at maximum capacity (i.e., 3,742,327 gallons per year).

B) The NO_x maximum limit will be lowered to 97.2 (lbs/hr) equivalent to 15 ppmvd @ 15% O_2 not later than 12/31/97 using appropriate combustion technology improvements or SCR.

C) Emission rates are based on 27°F at base load.

D) At full load conditions.

Best Available Control Technology (BACT) Determination
Central Florida Power, L.P.
Polk County
PSD-FL-190

The applicant proposes to construct a cogeneration facility near Ft. Meade, Polk County. This generator system will consist of a 184 MW General Electric PG7221FA combustion turbine generator (CT), equipped with a duct burner-fired heat recovery steam generator (HRSG), which will be used to power a nominal 74 MW steam turbine generator (ST).

The applicant has requested to burn natural gas for 8760 hours per year and distillate fuel oil, with a 0.05 percent sulfur content for a maximum 3,742,327 gallons per year. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility at base load, 27°F and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Gas		Oil	Total	PSD Significant Emission Rate (TPY)
	PG7221FA (8460 hrs)	Duct Burner (8760 hrs)	PG7221FA (300 hrs)		
NO_x	684.7	43.8	48.9	777.4	40
SO_2	20.5	1.3	15	36.8	40
PM/PM_{10}	38.1	4.4	2.6	45.1	25/15
CO	206.5	43.8	14.8	265.1	100
VOC	11.80	12.7	1.1	25.6	40
H_2SO_4	2.5	0.16	1.9	4.5	7
Be	nil	nil	6.94×10^{-4}	6.94×10^{-4}	0.0004
Hg	nil	nil	8.32×10^{-4}	8.32×10^{-4}	0.1
Pb	nil	nil	2.47×10^{-4}	2.47×10^{-4}	0.6
As	nil	nil	1.17×10^{-3}	1.17×10^{-3}	0

Florida Administrative Code (F.A.C.) Rule 17-212.400(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

June 15, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) Control Technology: Dry Low-NO_x Burners when firing natural gas and steam/water injection when firing distillate oil
SO_2	0.05% sulfur by weight (fuel oil firing)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

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, than the

next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

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

- Combustion Products (e.g., particulates). 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.

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

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not exceed 9 lbs/hr and 17 lbs/hr, respectively. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

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

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

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

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed combined cycle turbine is on exhaust concentrations of 15 ppmv for natural gas firing and 30 ppmv for fuel oil firing.

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

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

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst are not considered to be technically feasible for gas turbines fired with fuel oil.

Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be technically feasible for this natural gas-fired unit; however, the cost of $10,000 per ton for the PG7221FA of CO removed will have an adverse economic impact on this project.

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

ACID GASES

Nitrogen Oxides (NO_x)

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

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

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

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

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

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

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

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 of more than 7 million kwh per year.
f) Incremental cost effectiveness for the application of SCR technology to the Central Florida Power project was considered to be $7,400 per ton of NO_x removed.

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

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

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

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

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

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

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $3,364,400 for the PG7221FA. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For this project, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using dry low-NO_x (natural gas) and water injection (oil firing) will be 702.1 tons/year (at 72°F). Assuming that SCR would reduce the NO_x emissions by 65%, about 245.7 TPY would be emitted annually. When this reduction (456.4 TPY) is taken into consideration with the total levelized annual operating cost of $3,364,400; the cost per ton of controlling NO_x is $7,400. This calculated cost is higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will likely be available by

1997, the Department has accepted the water/steam injection (for distillate fuel oil firing), the dry low-NO_x burner design, and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 12/31/97).

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for this turbine [$7,400 per ton (natural gas)] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water/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 General Electric is developing programs for the PG7221FA 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 12/31/97. For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of the permit pursuant to F.A.C. Rule 17-4.080.

CO Control

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

Other Emissions Control

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

The emission limits for the Central Florida Power, L.P. project are thereby established as follows:

258 MW COMBINED CYCLE COMBUSTION TURBINE
100 MMBtu/hr Duct Burner

Pollutant	Emission Standards/Limitations[a] Oil[b]	Gas[c]	Method of Control
NO_x (CT)	42 ppmvd at 15% O_2; 362.2 lbs/hr	25 ppmvd at 15% O_2; 161.9 lbs/hr	Water Injection/ Dry Low-NO_x Combustor
		15 ppmvd at 15% O_2; 97.2 lbs/hr	Dry Low-NO_x Combustor or any other NO_x Control Technology
NO_x (DB)		0.1 lbs/MMBtu	
CO (CT)	98.4 lbs/hr	49 lbs/hr	Combustion
CO (DB)		10 lbs/hr	
PM/PM_{10} (CT)	17 lbs/hr	9 lbs/hr	Combustion
PM/PM_{10} (DB)		0.01 lbs/MMBtu	
SO_2 (CT)	99.7 lbs/hr	4.9 lbs/hr	Distillate Fuel Oil (0.05% S)
SO_2 (DB)		0.3 lbs/hr	
H_2SO_4 (CT)	1.2 lbs/hr	5.95×10^{-1} lbs/hr	Distillate Fuel Oil (0.05% S)
H_2SO_4 (DB)		3.7×10^{-2} lbs/hr	
VOC (CT)	7.5 lbs/hr	2.8 lbs/hr	Combustion
VOC (DB)		2.9 lbs/hr	
Hg	3.0×10^{-6} lbs/MMBtu (5.5×10^{-3} lbs/hr)		Fuel Quality
Pb	8.9×10^{-6} lbs/MMBtu (1.65×10^{-2} lbs/hr)		Fuel Quality
Be	2.5×10^{-6} lbs/MMBtu (4.62×10^{-3} lbs/hr)		Fuel Quality
As	4.2×10^{-6} lbs/MMBtu (7.77×10^{-3} lbs/hr)		Fuel Quality

(a) Emissions calculated at base load and 27°F.
(b) Fuel oil with a maximum of 0.05% sulfur by weight.
(c) Natural gas (8760 hours per year), Fuel oil (3,742,327 gallons per calendar year).
(d) Initial NO_X emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_X emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_X combustor injection technology or any other combustion technology, but no later than 12/31/97.

<u>Details of the Analysis May be Obtained by Contacting</u>:

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

Recommended by:

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

May 4 1993
Date

Approved by:

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

May 17 1993
Date

Best Available Control Technology (BACT) Determination
Central Florida Power, L.P.
Polk County
PSD-FL-190

The applicant proposes to construct a cogeneration facility near Ft. Meade, Polk County. This generator system will consist of a 184 MW General Electric PG7221FA combustion turbine generator (CT), equipped with a duct burner-fired heat recovery steam generator (HRSG), which will be used to power a nominal 74 MW steam turbine generator (ST).

The applicant has requested to burn natural gas for 8760 hours per year and distillate fuel oil, with a 0.05 percent sulfur content for a maximum 3,742,327 gallons per year. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility at base load, 27°F and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Gas		Oil	Total	PSD Significant Emission Rate (TPY)
	PG7221FA (8460 hrs)	Duct Burner (8760 hrs)	PG7221FA (300 hrs)		
NO_x	684.7	43.8	48.9	777.4	40
SO_2	20.5	1.3	15	36.8	40
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CO	206.5	43.8	14.8	265.1	100
VOC	11.80	12.7	1.1	25.6	40
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Be	nil	nil	6.94×10^{-4}	6.94×10^{-4}	0.0004
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Pb	nil	nil	2.47×10^{-4}	2.47×10^{-4}	0.6
As	nil	nil	1.17×10^{-3}	1.17×10^{-3}	0

Florida Administrative Code (F.A.C.) Rule 17-212.400(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

<u>Date of Receipt of a BACT Application</u>

June 15, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) Control Technology: Dry Low-NO_x Burners when firing natural gas and steam/water injection when firing distillate oil
SO_2	0.05% sulfur by weight (fuel oil firing)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

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).

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next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

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

- Combustion Products (e.g., particulates). 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.

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

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not exceed 9 lbs/hr and 17 lbs/hr, respectively. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

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

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

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

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed combined cycle turbine is on exhaust concentrations of 15 ppmv for natural gas firing and 30 ppmv for fuel oil firing.

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

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

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

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $3,364,400 for the PG7221FA. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For this project, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using dry low-NO_x (natural gas) and water injection (oil firing) will be 702.1 tons/year (at 72°F). Assuming that SCR would reduce the NO_x emissions by 65%, about 245.7 TPY would be emitted annually. When this reduction (456.4 TPY) is taken into consideration with the total levelized annual operating cost of $3,364,400; the cost per ton of controlling NO_x is $7,400. This calculated cost is higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will likely be available by

1997, the Department has accepted the water/steam injection (for distillate fuel oil firing), the dry low-NO_x burner design, and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 12/31/97).

<u>BACT Determination by DER</u>

<u>NO_x Control</u>

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for this turbine [$7,400 per ton (natural gas)] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water/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 General Electric is developing programs for the PG7221FA 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 12/31/97. For this turbine, an even lower NO_x emission level than 15 (gas)/42 (oil) ppmvd, corrected to 15% O_2, may become a condition of the permit pursuant to F.A.C. Rule 17-4.080.

<u>CO Control</u>

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

<u>Other Emissions Control</u>

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

The emission limits for the Central Florida Power, L.P. project are thereby established as follows:

258 MW COMBINED CYCLE COMBUSTION TURBINE
100 MMBtu/hr Duct Burner

Pollutant	Emission Standards/Limitations[a] Oil[b]	Gas[c]	Method of Control
NO_x (CT)	42 ppmvd at 15% O_2; 362.2 lbs/hr	25 ppmvd at 15% O_2; 161.9 lbs/hr	Water Injection/ Dry Low-NO_x Combustor
		15 ppmvd at 15% O_2; 97.2 lbs/hr	Dry Low-NO_x Combustor or any other NO_x Control Technology
NO_x (DB)		0.1 lbs/MMBtu	
CO (CT)	98.4 lbs/hr	49 lbs/hr	Combustion
CO (DB)		10 lbs/hr	
PM/PM_{10} (CT)	17 lbs/hr	9 lbs/hr	Combustion
PM/PM_{10} (DB)		0.01 lbs/MMBtu	
SO_2 (CT)	99.7 lbs/hr	4.9 lbs/hr	Distillate Fuel Oil (0.05% S)
SO_2 (DB)		0.3 lbs/hr	
H_2SO_4 (CT)	1.2 lbs/hr	5.95×10^{-1} lbs/hr	Distillate Fuel Oil (0.05% S)
H_2SO_4 (DB)		3.7×10^{-2} lbs/hr	
VOC (CT)	7.5 lbs/hr	2.8 lbs/hr	Combustion
VOC (DB)		2.9 lbs/hr	
Hg	3.0×10^{-6} lbs/MMBtu (5.5×10^{-3} lbs/hr)		Fuel Quality
Pb	8.9×10^{-6} lbs/MMBtu (1.65×10^{-2} lbs/hr)		Fuel Quality
Be	2.5×10^{-6} lbs/MMBtu (4.62×10^{-3} lbs/hr)		Fuel Quality
As	4.2×10^{-6} lbs/MMBtu (7.77×10^{-3} lbs/hr)		Fuel Quality

(a) Emissions calculated at base load and 27°F.
(b) Fuel oil with a maximum of 0.05% sulfur by weight.
(c) Natural gas (8760 hours per year), Fuel oil (3,742,327 gallons per calendar year).
(d) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor injection technology or any other combustion technology, but no later than 12/31/97.

<u>Details of the Analysis May be Obtained by Contacting</u>:

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

Recommended by:

C.H. Fancy

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

May 4 1993
Date

Approved by:

Virginia B. Wetherell

Virginia B. Wetherell, Secretary
Dept. of Environmental Regulation

May 17 1993
Date

For Routing To Other Than The Addressee

To: Clair Location:

To: Location:

To: Location:

From: RECEIVED Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

RECEIVED
MAY 11 1993
D.E.R. OFFICE OF THE SECRETARY

MAY 14 1993
Division of Air Resources Management

TO: Virginia B. Wetherell

FROM: Howard L. Rhodes HLR

DATE: May 6, 1993

SUBJ: Approval of Construction Permit **AC**53-214903 (PSD-FL-190)
Central Florida Power, Limited Partnership

Attached for your approval and signature is a permit prepared by the Bureau of Air Regulation for the above mentioned company to construct/operate a 258 megawatt (MW) cogeneration facility. Natural gas will be the primary fuel for the cogeneration facility over its lifetime and distillate fuel oil will be used as a backup fuel. Air emission sources associated with the proposed project consist of the combustion turbine (CT) and supplemental firing in the heat recovery steam generator (HRSG). Nitrogen oxide (NO_x) emissions will be minimized by using dry low-NO_x technology for the CT and low-NO_x burners when duct firing. The use of natural gas will minimize the emissions of sulfur dioxide (SO_2) and other pollutants.

I recommend your approval and signature.

HLR/TH/plm

Attachments

RECEIVED

MAY 14 1993

Division of Air Resources Management

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

JUN 18 1993

4APT-AEB

RECEIVED

JUN 23 1993

Division of Air
Resources Management

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

RE: Central Florida Power Limited Partnership,
Tiger Bay Cogeneration Plant (PSD-FL-190)

Dear Mr. Fancy:

This is to acknowledge receipt of the final determination and Prevention of Significant Deterioration (PSD) permit for the above referenced facility, by your correspondence dated May 19, 1993. The proposed facility will be a 258 megawatt combined cycle cogeneration power plant. The proposed project consists of one advanced technology heavy-duty industrial gas turbine electric generating unit, with a duct burner-fired heat recovery steam generator, and a steam turbine generator.

Your determination proposes to limit NO_x emissions from the combustion turbine through advanced dry low-NO_x combustors and water injection, to limit NO_x emissions from the duct burner through combustion design, to limit CO and VOC emissions from the combustion turbine and duct burner through combustion control, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuels. In addition, this facility will meet revised, lower NO_x limits no later than December 31, 1997, through advanced combustor technology or the use of selective catalytic reduction.

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on the package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

Brian L. Beals, Chief
Source Evaluation Unit
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

40TPA530223
Central Florida

cc: J. Heron
C. Holladay
B. Thomas, SW Dist
J. Bunyak, NPS
K. Kosky, P.E., KBN
L. Novak, Polk Co

KBN

March 11, 1993

R[illegible] EIVED

MAR 16 1993

Div

Resources [illegible]

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 3299-2400

RE: Central Florida Power Limited Partnership (CFPLP)
Tiger Bay Cogeneration Plant
AC 53-214903; PSD-FL-190

Dear Clair:

This correspondence provides technical information for the Department's consideration concerning the comments received from the U.S. Fish and Wildlife Service (USFWS) dated February 5, 1993 on the above referenced project. Specifically, the USFWS suggested the final permit for the project include a statement that selective catalytic reduction (SCR) be installed if the 15 ppmvd (corrected to 15 percent oxygen) emission limit is not met and that the Department re-establish an allowable emissions limit as best available control technology (BACT) if actual emissions are tested less than 15 ppmvd. The information contained herein and in the permit record clearly suggest that the final permit should not contain the suggestions made by the USFWS. The rationale is presented below.

Mandating SCR

Modifying the proposed language of the permit to include a provision mandating SCR is unwarranted. The condition as proposed by the Department clearly recognizes that it will be at the determination of the Department whether SCR will be installed. This allows flexibility to incorporate other design features to meet the 15 ppmvd NOx emission limit if desired by the Department. As "pollution prevention" technology progresses over the next several years there may be other options of lowering NOx to meet emission limits. For example, the combined use of dry-low NOx combustion and wet injection may prove to be a viable technique. Research is also being performed in the area of fuel additives. Mandating the installation of SCR, if a permit limit is not met, does not recognize the development of future technologies and does not provide the Department or CFPLP the inherent flexibility to make an appropriate decision.

Lowering the Permit/BACT Limit

Incorporating a provision in the permit that will require the lowering the BACT limit is not appropriate for several reasons. First, there have been no criteria proposed for establishing such a lower limit. While the initial performance tests may find a NOx emission rate lower than 15 ppmvd corrected, this tested rate will only be an accurate representation of NOx emissions that occurred during the specific conditions observed during the tests. Combustion turbines are sensitive to ambient meteorological

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

conditions such as temperature and relative humidity. Changes in meteorological conditions, for which CFPLP will have no control, may cause changes in NOx emissions. Such conditions are recognized in the margins incorporated into the design features of the control equipment. An example of how operational conditions can affect NOx emissions was previously supplied to the Department for the Orlando CoGen Limited, L.P. Project. Information was supplied to the Department that indicated that actual NOx tested as low as 9 to 13 ppmvd for the combustion turbine proposed for the project. However, the vendor would only guarantee 15 ppmvd since margins are required to assure compliance with the permit limits under all operating scenarios. The Department accepted this rationale in this permit decision.

Second, the proposed project is being designed for operation in late 1994 to early 1995. While it is recognized that combustion turbine units proposed for operation in the future (> 1997) have proposed lower limits, equipment proposed for these projects may not be applicable to the proposed project. The earlier commercial operation date for the CFPLP facility suggests that differences in equipment may result.

Third, all equipment degrades whether it be dry low-NOx combustors, SCR or a fabric filter. The emission margins built into all control equipment recognizes this fact and an appropriate emission limit must be established to account for emission changes as a result of equipment degradation.

Apparent Preference for Technology Comments by USFWS

The State of Florida has full authority for implementing the federally mandated Prevention of Significant Deterioration program through approval of its regulations and State Implementation Plan (SIP). The federal agencies comment on the PSD applications and have differing authority. The USFWS which is the designated Federal Land Manager for National Wilderness Areas Class I areas has review authority of air quality related values in such areas. The Environmental Protection Agency has authority in establishing the implementing regulations for PSD review and approval, and establishing guidelines for modeling and control technology review. For the CFPLP project, the EPA comments (see letter dated February 16, 1993), suggest that the Department's permitting decision was appropriate. The EPA is clearly the appropriate agency regarding control technology issues. In contrast, the USFWS which is the appropriate agency for air quality related values, had no adverse comments regarding the NOx impacts in the Class I area. Indeed, the USFWS indicated that the NOx impacts at the emission limits proposed by the Department were not significant. The USFWS comments should be viewed in this context; i.e., lowering the NOx emission limit will not change the conclusion reached regarding impacts (i.e., impacts will still not be significant). Moreover, the EPA comments concerning control technology (as well as emission limits) should take preference over USFWS comments.

Conclusion

The technical information presented herein and the permit record clearly indicate that the emission limits proposed by the Department in the draft permit are appropriate. Taken together with the commercial concerns expressed by CFPLP (see letter of March 10, 1993, from Destec Energy the controlling partner), we respectively request the Department not incorporate the comments made by the USFWS into the final permit.

KBN

As always, the assistance of you and your staff are greatly appreciated. Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President and Principal Engineer
Florida Registration No. 14996

cc: Terrsa Heron
Preston Lewis
R. Chatham
C. Holladay
J. Harper, EPA
J. Bunyak, NPS
B. Thomas, SWD

attachment

KFK/mlb

DESTEC ENERGY

March 10, 1993

DESTEC ENERGY, INC.
2500 CITYWEST BLVD., SUITE 150
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 735-4000

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

VIA FEDERAL EXPRESS

Re: Central Florida Power, L.P. - DER No. AC53-214903 & PSD-FL-190

Dear Mr. Fancy:

On behalf of Central Florida Power, L.P. (CFPLP), I respectfully request the following comments be entered into the Department's record:

We have given serious consideration to the issue of revising emission limits after performance testing and emission data if such a lower rate is achievable. Our experience with lenders indicates that they would be unlikely to commit funds to a project with such a permit condition. We, as well as the financial community, are well aware that the regulatory agencies have the authority to impose new requirements on existing facilities. This "regulatory risk" is taken into account during the development of the project financing. A specific condition in the permit stating the Department's authority to revise the allowable emission limit would bring the "reliance on" the permit into question. Therefore, we request that no such condition be in the final permit for a change in the emission limits based on actual emission rates and that the Department rely on the regulation to provide for revision to the allowable limits.

We respectfully request that you consider our comment and would be pleased to address any other questions or concerns you might have. We appreciate the efforts on the part of the Department in reviewing our permit application and we look forward to receiving our permit.

Sincerely,

Frost W. Cochran
Project Finance Manager

RECEIVED
MAR 11 1993
Division of Air
Resources Management

FWC/nl

cc: Bob Taylor
Ken Kosky
J. Reynolds
FWC/nl C. Holladay

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Patter

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION IV - ATLANTA, GEORGIA
AIR, PESTICIDES & TOXICS MANAGEMENT DIVISION

AIR ENFORCEMENT BRANCH
FACSIMILE TRANSMISSION SHEET

DATE: 2/15/93 # OF PAGES: 2

TO: Clair H. Fancy PHONE #:

ADDRESS: FDER FAX:

FROM: Scott Davis

If the following pages are received poorly, please call Angela at (404) 347-5014

SPECIAL INSTRUCTIONS FOR RECEIVER:

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365
FAX (404) 347-3059

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

FEB 16 1993

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

RE: Central Florida Power Limited Partnership,
Tiger Bay Cogeneration Plant (PSD-FL-190)

Dear Mr. Fancy:

This is to acknowledge receipt of the preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility, by your letter dated January 15, 1993. The proposed facility will be a 258 megawatt combined cycle cogeneration power plant. The proposed project consists of one advanced technology heavy-duty industrial gas turbine electric generating unit, with a duct burner-fired heat recovery steam generator, and a steam turbine generator.

Your determination proposes to limit NO_x emissions from the combustion turbine through advanced dry low-NO_x combustors and water injection, to limit NO_x emissions from the duct burner through combustion design, to limit CO and VOC emissions from the combustion turbine and duct burner through combustion control, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuels. In addition, this facility will meet revised, lower NO_x limits no later than December 31, 1997, through advanced combustor technology or the use of selective catalytic reduction.

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on the package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

Brian L. Beals, Chief
Source Evaluation Unit
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Buron
C. Holladay
B. Thomas, SW Dist
J. Bunyak, NPS
K. Kosky, KBN
J. Novak, P. County

RECEIVED

FEB 22 1993

Division of Air
Resources Management

KBN

February 8, 1993

RECEIVED

FEB 09 1993

Division of Air
Resources Management

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

Re: Central Florida Power Limited Partnership
Tiger Bay Cogeneration Plant
PSD-FL-190
AC 53-214903

Dear Mr. Fancy:

Enclosed please find the Affidavit of Publication for advertisement of the Notice of Intent to Issue Permit for this project. As shown, the advertisement was published in The Polk County Democrat on February 4, 1993 and satisfies the publication requirements of the Intent to Issue.

If you have any questions concerning this material, please call me at your earliest convenience.

Sincerely,

Robert C. McCann for

Kennard F. Kosky, P.E.
President

Enclosure

cc: Robert I. Taylor, Central Florida Power, L.P.
Robert Chatham, Destec Energy, Inc.
Teresa Heron, FDER
Project File
C. Holladay
B. Thomas, SW Dist.
J. Harper, EPA
J. Bunyak, NPS
[illegible]

12018A1/14

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1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

BEST AVAILABLE COPY

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 ____________ Linda K. Holcomb, who on oath says that (s)he is Ad Manager 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 Permit in the matter of Central Florida Power

____

in the ____________ Court, was published in said newspaper in the issues of February 4, 1993.

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 Linda K. Holcomb

The foregoing instrument was acknowledged before me this 5th day of Feb.,

19 93, by Linda K. Holcomb,

who is personally known to me.

Teresa M. Pacetti
(Signature of Notary Public)

Teresa M. Pacetti
(Printed or typed name of Notary Public)
Notary Public

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA

Notary Public, State of Florida
TERESA M. PACETTI
My Comm. Exp. Dec. 19, 1995
Comm. No. CC 169408

STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL
REGULATION
NOTICE OF
INTENT TO
ISSUE PERMIT

The Department of Environmental Regulation gives notice of its intent to issue a PSD permit to Central Florida Power. Limited Partnership (CFPLP), County Road 630, 5 miles west of Ft. Meade, Polk County, Florida, to construct a 258 MW cogeneration facility. A determination of Best Available Control Technology (BACT) was required. The Department is issuing this Intent to Issue for the reasons 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 diffe rent from the position taken by i in this Notice. Persons whos substantial interests will b affected by any decision of th Department with regard to th application have the right to peti tion to become a party to th proceeding. The petition mus conform to the requirements spec ified above and be filed (receive within 14 days of publication o this notice in the Office of Genera Counsel at the above address o the Department. Failure to peti tion within the allowed tim frame constitutes a waiver of an right such person has to request hearing under Section 120.5 F.S., and to participate as a part ... subs

quent 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 Regulation, Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, Department of Environmental Regulation, 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's Tallahassee address. 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.
Feb. 4, 1993—0301

United States Department of the Interior

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

February 5, 1993

RECEIVED

FEB 08 1993

Division of Air
Resources Management

Mr. C. H. 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 completed our review of Central Florida Power's (CFP) permit application and the Florida Department of Environmental Regulation's (FDER) Technical Evaluation and Preliminary Determination document regarding the proposed 258 MW Tiger Bay cogeneration project. This facility would be located near Ft. Meade, approximately 120 km southeast of the Chassahowitzka Wilderness Area (WA), a Class I air quality area administered by the Fish and Wildlife Service. The proposed project would be a significant emitter of particulate matter (PM), beryllium (Be), carbon monoxide (CO), arsenic (As), and nitrogen oxides (NO_x). In addition, small amounts of sulfur dioxide (SO_2), volatile organic compounds (VOC), mercury (Hg), lead (Pb), and sulfuric acid mist (H_2SO_4) would be emitted. We are pleased to see that CFP would minimize SO_2 and H_2SO_4 emissions by burning natural gas as the primary fuel, and fuel oil with a maximum sulfur content of 0.05 percent as the backup fuel. This fuel choice allows CFP to avoid the Class I SO_2 increment consumption issue faced by new, high sulfur fuel-burning projects in the vicinity of the Chassahowitzka WA.

CFP proposes to further minimize emissions from the combustion turbine by using proper combustion controls, water injection, and advanced dry low-NO_x combustors. We agree that using proper combustion controls and burning a low sulfur fuel represent best available control technology (BACT) for PM, Be, As, CO, VOC, SO_2, and H_2SO_4. For NO_x, we still 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.

→ P 3/31

Check Sheet

Company Name: Central Florida Power LP ~~Phosphates~~
Permit Number: AC-53-214903
PSD Number: PSD-FL-190
County: Polk
Permit Engineer: Teresa
Others involved:

DER Letter 7/14/92 ?

Application:

- [x] Initial Application
- [x] Incompleteness Letters
- [x] Responses
- [ ] Final Application (if applicable)
- [x] Waiver of Department Action
- [ ] Department Response

Intent:

- [x] Intent to Issue
- [x] Notice to Public
- [x] Technical Evaluation
- [x] BACT Determination
- [ ] Unsigned Permit

  Attachments:
  - [ ]
  - [ ]
  - [ ]

- [ ] Correspondence with:
  - [x] EPA
  - [ ] Park Services
  - [ ] County
  - [ ] Other
- [x] Proof of Publication
- [ ] Petitions - (Related to extensions, hearings, etc.)

Final Determination:

- [x] Final Determination
- [x] Signed Permit
- [x] BACT Determination

Post Permit Correspondence:

- [ ] Extensions
- [x] Amendments/Modifications
- [ ] Response from EPA
- [ ] Response from County
- [ ] Response from Park Services

- [x] Other

It is evident that the BACT process is driving emissions from combustion turbines downward, and that applicants are looking for ways to inherently lower emissions, rather than opting for add-on flue gas cleaning technologies. 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. The Technical Evaluation and Preliminary Determination document for the Tiger Bay project mentions that 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 CFP's low-NO_x burner design with a maximum NO_x emission limit of 25 ppm (while burning gas) 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, 9 ppm. Therefore, while we do not object to the FDER allowing CFP to emit at the 25 ppm NO_x rate until GE develops the combustors, we feel that draft permit condition Number 15 should be revised. As written now, it suggests that SCR <u>may be</u> required if the lower NO_x emission limit of 15 ppm cannot be met. We recommend that this permit condition require CFP 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.

Regarding CFP's analyses of Tiger Bay's potential impacts on the Chassahowitzka WA, CFP performed a Level I VISCREEN analysis and showed that there would be low potential for plume impacts in the wilderness area. In addition, CFP addressed potential effects on aquatic and terrestrial resources in the Chassahowitzka WA from increased nitrogen input. As we discussed in detail in our recent letter on the Kissimmee project, we are concerned about increased nitrogen input into the wilderness area and potential problems associated with nutrient enrichment in the aquatic ecosystem. However, because CFP's modeling shows that the annual average nitrogen dioxide impacts in the wilderness area from the Tiger Bay facility alone would be 0.014 micrograms per cubic meter (ug/m^3), less than our proposed significant impact level of 0.025 ug/m^3, we would not expect the project to contribute significantly to this problem.

If you have any questions regarding this matter, please contact Ms. Tonnie Maniero of our Air Quality office in Denver at 303/969-2071.

Sincerely yours,

Harold W Benson

for James W. Pulliam, Jr.
Regional Director

cc: J. Hurn
C. Holladay
B. Thomas, SW Dist
J. Bunyak, NPS
L. Novak, Polk Co.
K. Kooky, KBN
J. Harper, EPA

P 230 524 382

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Governor

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

Virginia B. Wetherell
Secretary

August 5, 1993

Mr. Robert S. Chatam, P.E.
DESTEC ENERGY, INC.
2500 Citywest Blvd., Suite 150
P.O. Box 4411
Houston, Texas 77210-4411

Dear Mr. Chatam:

RE: Central Florida Power L.P.
Permit No. AC53-214903, PSD -FL-190

The Department is in receipt of your letter dated July 30, 1993 regarding several design changes to your proposed Tiger Bay Cogeneration facility.

We have reviewed your letter and have no adverse comments. An "as built" plot and site plan should be included with the Certificate of Completion when you apply for an operation permit for this facility. Thank you for the opportunity to review and comment on this letter.

Sincerely,

CH Fancy

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

CHF/TH/bjb

Florida Department of

Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 11, 1993

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

Dear Mr. Kosky:

This in response to your recent letter notifying the Department of a design change for the Tiger Bay Cogeneration Facility (PSD-FL-190) consisting of a lower operating load of 60 percent. This design change will neither increase emissions nor result in a substantially different ambient impact. This operation will have no impact as far as the construction permit emission limits are concerned. Consequently, a construction permit modification is not required for this design change. However, it is required that this and all other substantive changes in the final design and construction be reported in the operation permit application.

If you have further questions, please contact Preston Lewis, Teresa Heron or Cleve Holladay at (904-488-1344).

Sincerely,

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

CHF/CH

cc: Robert Chatham, Destec Energy, Inc.
Robert I. Taylor, Tiger Bay L.P.
Bill Thomas, SWD

KBN

January 30, 1993

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

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FEB 01 1993

Division of Air
Resources Management

Re: Central Florida Power Limited Partnership
Tiger Bay Cogeneration Plant
PSD-FL-190
AC 53-214903

Dear Mr. Fancy:

After review of the Technical Evaluation and Preliminary Determination (TEPD) for this project, dated January 15, 1993, several items in the draft permit were discussed with Ms. Teresa Heron for clarifications or corrections. These items, which were sent by facsimile to Teresa on January 21, 1993, are included as an attachment to this letter. From those discussions, the revisions, which were not considered significant by Teresa, are summarized as follows:

1. Specific Condition No. 5, page 5 of 10, TEPD- the operating parameters are for the 184 MW Combustion Turbine. Therefore, the wording, 74 MW Steam Turbine, can be eliminated from the heading.

2. Specific Condition No. 8, page 7 of 10, TEPD- Method 201, Method 12, Method 101A, and Method 8, as referenced, are either not applicable or were inadvertantly inserted in this condition. These methods should be deleted.

Method 202, Determination of Condensible Particulate Emissions from Stationary Sources, should be inserted and will be used with Method 201A.

3. Specific Condition No. 9, page 7 of 10, TEPD- Method 201A and Method 201 are listed for determining the initial compliance status of particulate matter emissions. This should be changed to Method 201A and Method 202.

4. Specific Condition No. 13, page 7 of 10, TEPD- Reference to the "proposed" NOx standard should be revised to the "NSPS" NOx standard since the standard is a final regulation.

12018-0400

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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KBN

5. Table 1, TEPD- Several corrections regarding the emission rates and wording:

   a. For CO(CT), oil- change 98 lbs/hr to 98.4 lbs/hr
   b. For opacity, oil- insert footnote D
   c. For Hg, As, Be, Pb- include emission rate in lb/hr and TPY
   d. For Hg, As, Be, Pb- change factor of 10^{-12} to 10^{-6}
   e. In footnote A- delete No. 2 in reference to distillate oil
   f. In footnote B- include emission rate of 97.2 lb/hr in reference to the NOx emission limit of 15 ppmvd; 15 ppmv should be ppmvd

6. Best Available Control Technology (BACT) Determination, Table on page 9:

   a. For NOx(CT)- include lb/hr emission rates and correct ppmv to ppmvd
   b. For CO(CT)- change 98 lbs/hr to 98.4 lbs/hr
   c. For Hg, As, Be, Pb- include emission rate in lb/hr and TPY
   d. For Hg, As, Be, Pb- change factor of 10^{-12} to 10^{-6}
   e. In footnote b- delete No. 2 in reference to distillate oil
   f. in footnote c- change 8460 hours per year to 8760
   g. in footnote c- delete 300 hours per year and insert 3,742,327 gallons per calendar year

Items that remained as issues to be addressed include the following.

1. The PM10 emission limits for the CT firing natural gas and oil are currently expressed in units of lbs/MMBtu. However, based on the manufacturer's guarantee, the emission limits were presented in the application in units of lb/hr (see recommended changes in Table 1 of the TEPD; page 3 and table on page 9 of the BACT Determination). As shown in the attached KBN Table 1, the PM emission rate may exceed 0.01 lbs/MMBtu for oil-firing at base load and high temperature conditions and at 70 percent load for the range of temperatures. Although the emission limit of 0.01 lbs/MMBtu is based on base load and ambient temperature of 27 °F in the tables, the text does not mention the operating condition or temperature. To avoid this potential confusion, it is recommended that the CT emission limit for firing natural gas and fuel oil be expressed as 9 and 17 lb/hr, respectively.

2. On page 7 of the BACT Determination, it is stated that General Electric (GE) is currently developing programs using both steam/water injection and dry low NOx combustor to achieve NOx emission control level of 9 ppm when firing natural gas. From recent discussions with GE, it is our undersatnding that the emission control level that they are attempting to achieve is 15 ppm.

3. To be consistent with emission rates presented for most pollutants, it is recommended that the limits for sulfuric acid mist (H_2SO_4) should be expressed to 3 three significant digits (see Table 1 of the TEPD and the table on page 9 of the BACT Determination.

KBN

We appreciate your efforts in preparing the draft permit and reviewing our comments. Please call me if there any further questions on the material submitted.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

Enclosure

cc: Robert I. Taylor, Central Florida Power, L.P.
Robert Chatham, Destec Energy, Inc.
Teresa Heron, FDER
C. Holladay

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Permit: AC 53-214903
PSD-FL-190

PS Form 3800, June 1991

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PS Form 3811, November 1990 U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

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Carol M. Browner, Secretary

October 9, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert I. Taylor, Project Manager
Central Florida Power, L.P.
2500 City West Blvd., Suite 150
Houston, Texas 77042

Dear Mr. Taylor:

This letter is to confirm the Department's conversation with Mr. Ken Kosky that additional information (updated process flow diagram showing the volumetric flow rates) is needed to complete your application for permit to construct the Tiger Bay Cogeneration Plant (File No. AC53-214903/PSD-FL-190). We are working directly with Mr. Kosky to obtain the needed information and will resume processing this application when it is complete.

If you have any questions on this matter, please write to me or call Mirza Baig, review engineer, at (904) 488-1344.

Sincerely,

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

CHF/MB/plm

cc: Ken Kosky, KBN
B. Thomas, SW Dist.
J. Harper, EPA
B. Mitchell, NPS

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DESTEC ENGINEERING, INC.
2500 CITYWEST BLVD., SUITE 150
P. O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 735-4000

October 23, 1992

Deanna
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10/28/92

Mr. G. Preston Lewis, P.E.
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Central Florida Power Limited Partnership
Tiger Bay cogeneration plant
PSD-FL-190
AC 53-214903

Dear Mr. Lewis,

Per our conversation on October 22, I want to personally thank you for your involvement and decision to determine our application as administratively complete as of October 9, 1992 and your commitment to issue the draft permit by December 9, 1992. KBN and I look forward to working with Mr. Mirza Baig and your department in the review and processing of our application and final issuance of the permit.

Please call me at (713) 735-4087 should you or your department have questions or comments about our application.

Sincerely,

Robert S. Chatham

Robert S. Chatham, P.E.
Senior Environmental Engineer

RSC:tk

plewis.WPR

cc:Mr. Mirza Baig - FDER, Tallahassee

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A SUBSIDIARY OF DESTEC ENERGY, INC.

KBN

October 9, 1992

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

Attention: Mirza Baig

RE: Central Florida Power Limited Partnership
Tiger Bay (formerly Central Florida) Cogeneration Plant
PSD-FL-190
AC 53-214903

Dear Mirza:

As we discussed today, we will be sending to you information relating to the volumetric flow rates in the process flow diagrams sent in our letter of August 26, 1992.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal Engineer

KFK/mlb

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Mirza.ltr/Kosky

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

September 9, 1992

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

Re: Central Florida Power Limited Partnership
Tiger Bay (formerly Central Florida) Cogeneration Plant
PSD-FL-190
AC 53-214903

Dear Mr. Fancy:

This correspondence presents a clarification of Attachment 1, Manufacturer's Design Specifications for the Combustion Turbine, provided in my letter of August 26, 1992, and discussed between Mr. Robert McCann, KBN, and Mirza Baig on August 27, 1992. In that attachment, design specifications were given for GE PG7221(FA) and Westinghouse 501F combustion turbines. In August, more recent information was obtained, and the Westinghouse data are slightly different from the information presented in the permit application submitted on June 12, 1992.

As shown in Tables 1 through 4, the changes in maximum emission rates for the Westinghouse turbine are minor and generally are within approximately 2 percent of the rates specified in the permit application (see Tables 5 through 8). The emission rates for other regulated and non-regulated pollutants increase slightly due to the slight increase in the heat input rate (i.e., MMBtu/hr) which generally is the basis of the emission factor for those pollutants. Comparisons of the maximum emissions for the Westinghouse and GE turbines as presented in the permit application and for the revised Westinghouse turbine are presented in Tables 9 through 12. As shown, the emission data, in tons per year (TPY), for the GE machine at 72°F ambient temperature are higher for all pollutants except VOC when compared to the Westinghouse data. The revised maximum VOC emission rate for the Westinghouse turbine is slightly higher than that presented in the permit application (45.6 TPY compared to 45.3 TPY).

Table 3-1 from the support document to the PSD permit application has been revised to reflect the worst-case emission rates for each pollutant from either turbine. The worst-case emission rates are used to determine pollutant applicability under PSD regulations by comparing the maximum allowable emissions for the project to the PSD significant emission rates.

The modeling analysis presented as part of the permit application also does not significantly change and still provides a conservative estimate of short-term and annual impacts. The impacts were based on the the worst-case emission rates from either the GE emission data or the previous Westinghouse emission data which are still higher than the updated Westinghouse emission data.

12018A1/4

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

KBN

Therefore, the updated design specifications for the Westinghouse turbine are not a significant change from the material presented in the original application and should not materially affect any conclusions drawn from original application.

Please call me if there any further questions on the material submitted.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/dmpm

Enclosure

cc: Robert I. Taylor, Central Florida Power, L.P.
Robert Chatham, Destec Engineering, Inc.
Mirza Baig, FDER
File (2)
C. Holladay
B. Thomas, SW Dist.
G. Harper, EPA
B. Mitchell, NPS

Table 3-1. Net Increase in Emissions Due To the Central Florida Cogeneration Facility Compared to the PSD Significant Emission Rates (REVISED)

Pollutant	Emissions (TPY): Potential Emissions From Proposed Facility[a]: Permit Application	Emissions (TPY): Potential Emissions From Proposed Facility[a]: Revised	Emissions (TPY): Significant Emission Rate	PSD Review
Sulfur Dioxide[b]	33.1 (GE)	33.1 (GE)	40	No
Particulate Matter (TSP)	45.0 (GE)	45.0 (GE)	25	Yes
Particulate Matter (PM10)	45.0 (GE)	45.0 (GE)	15	Yes
Nitrogen Dioxide	702.1 (GE)	702.1 (GE)	40	Yes
Carbon Monoxide	243.1 (GE)	243.1 (GE)	100	Yes
Volatile Organic Compounds	45.3 (W)	45.6 (W)	40	Yes
Lead	0.00219 (GE)	0.00219 (GE)	0.6	No
Sulfuric Acid Mist	4.2 (GE)	4.2 (GE)	7	No
Total Fluorides	0.00802 (GE)	0.00802 (GE)	3	No
Total Reduced Sulfur	NEG	NEG	10	No
Reduced Sulfur Compounds	NEG	NEG	10	No
Hydrogen Sulfide	NEG	NEG	10	No
Asbestos	NEG	NEG	0.007	No
Beryllium	0.000616 (GE)	0.000616 (GE)	0.0004	Yes
Mercury	0.000739 (GE)	0.000739 (GE)	0.1	No
Vinyl Chloride	NEG	NEG	1	No
Benzene	NEG	NEG	0	No
Radionuclides	NEG	NEG	0	No
Inorganic Arsenic	0.00104 (GE)	0.00104 (GE)	0	Yes

Note: GE = General Electric.
NEG = Negligible.
W = Westinghouse.

All calculations based on 72°F base load condition.

[a] Maximum annual emissions based on the gas turbine firing distillate oil and natural gas for 300 and 8,460 hours, respectively, and duct burner firing natural gas for 8,760 hours. Tables A-15 through A-18 present emissions for the GE machine while Tables A-33 through A-36 present emissions for the Westinghouse machine.

[b] Based on a maximum sulfur content specification of 0.05 percent in fuel oil.

W501DIFF
9/03/92

Table 1. Difference in Maximum Emissions for Criteria Pollutants for Tiger Bay Cogeneration Facility- Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	-9.00E-01	-1.00E-01	0.00E+00	2.00E-01	1.00E-01	1.00E-01	0.00E+00	0.00E+00	0.00E+00	-9.00E-01	-1.00E-01	0.00E+00
TPY	-1.35E-01	-1.50E-02	0.00E+00	8.46E-01	4.23E-01	4.23E-01	0.00E+00	0.00E+00	0.00E+00	7.11E-01	4.08E-01	4.23E-01
Sulfur Dioxide:												
lb/hr	-1.70E+00	-7.94E-01	-6.95E-01	3.93E-02	3.78E-02	3.64E-02	0.00E+00	0.00E+00	0.00E+00	-1.70E+00	-7.94E-01	-6.95E-01
TPY	-2.55E-01	-1.19E-01	-1.04E-01	1.66E-01	1.60E-01	1.54E-01	0.00E+00	0.00E+00	0.00E+00	-8.86E-02	4.06E-02	4.95E-02
Nitrogen Oxides:												
lb/hr	-7.98E-01	4.82E+00	4.27E+00	-6.21E+00	2.49E+00	2.69E+00	0.00E+00	0.00E+00	0.00E+00	-7.98E-01	4.82E+00	4.27E+00
TPY	-1.20E-01	7.22E-01	6.40E-01	-2.63E+01	1.05E+01	1.14E+01	0.00E+00	0.00E+00	0.00E+00	-2.64E+01	1.13E+01	1.20E+01
Carbon Monoxide:												
lb/hr	-2.58E+00	1.36E+00	1.67E+00	1.27E+00	2.70E-01	2.65E-01	0.00E+00	0.00E+00	0.00E+00	-2.58E+00	1.36E+00	1.67E+00
TPY	-3.87E-01	2.05E-01	2.51E-01	5.37E+00	1.14E+00	1.12E+00	0.00E+00	0.00E+00	0.00E+00	4.98E+00	1.34E+00	1.37E+00
VOCs (as methane):												
lb/hr	-1.21E-01	1.59E-01	1.62E-01	6.16E-02	6.13E-02	6.39E-02	0.00E+00	0.00E+00	0.00E+00	-1.21E-01	1.59E-01	1.62E-01
TPY	-1.82E-02	2.38E-02	2.43E-02	2.61E-01	2.59E-01	2.70E-01	0.00E+00	0.00E+00	0.00E+00	2.43E-01	2.83E-01	2.94E-01
Lead:												
lb/hr	4.54E-06	1.37E-04	1.37E-04	NA	NA	NA	NA	NA	NA	4.54E-06	1.37E-04	1.37E-04
TPY	6.81E-07	2.06E-05	2.05E-05	NA	NA	NA	NA	NA	NA	6.81E-07	2.06E-05	2.05E-05

Note: NA = not applicable

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Table 2. Difference in Maximum Emissions of Other Regulated Pollutants for Tiger Bay Cogeneration Facility
Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	2.14E-06	6.47E-05	6.44E-05	NA	NA	NA	NA	NA	NA	2.14E-06	6.47E-05	6.44E-05
	TPY	3.21E-07	9.71E-06	9.67E-06	NA	NA	NA	NA	NA	NA	3.21E-07	9.71E-06	9.67E-06
Beryllium													
	lb/hr	1.27E-06	3.85E-05	3.84E-05	NA	NA	NA	NA	NA	NA	1.27E-06	3.85E-05	3.84E-05
	TPY	1.91E-07	5.78E-06	5.75E-06	NA	NA	NA	NA	NA	NA	1.91E-07	5.78E-06	5.75E-06
Mercury													
	lb/hr	1.53E-06	4.62E-05	4.60E-05	NA	NA	NA	NA	NA	NA	1.53E-06	4.62E-05	4.60E-05
	TPY	2.29E-07	6.94E-06	6.91E-06	NA	NA	NA	NA	NA	NA	2.29E-07	6.94E-06	6.91E-06
Fluoride													
	lb/hr	1.66E-05	5.01E-04	4.99E-04	NA	NA	NA	NA	NA	NA	1.66E-05	5.01E-04	4.99E-04
	TPY	2.49E-06	7.52E-05	7.49E-05	NA	NA	NA	NA	NA	NA	2.49E-06	7.52E-05	7.49E-05
Sulfuric Acid													
Mist	lb/hr	-2.08E-01	-9.73E-02	-8.52E-02	5.07E-03	4.87E-03	4.69E-03	0.00E+00	0.00E+00	0.00E+00	-2.08E-01	-9.73E-02	-8.52E-02
	TPY	-3.12E-02	-1.46E-02	-1.28E-02	2.14E-02	2.06E-02	1.98E-02	0.00E+00	0.00E+00	0.00E+00	-9.78E-03	6.01E-03	7.06E-03

Note: NA = not applicable

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9/03/92

Table 3. Difference in Maximum Emissions of Non-Regulated Pollutants for Tiger Bay Cogeneration Facility- Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese													
	lb/hr	7.14E-06	2.16E-04	2.15E-04	NA	NA	NA	NA	NA	NA	7.14E-06	2.16E-04	2.15E-04
	TPY	1.07E-06	3.24E-05	3.22E-05	NA	NA	NA	NA	NA	NA	1.07E-06	3.24E-05	3.22E-05
Nickel													
	lb/hr	8.67E-05	2.62E-03	2.61E-03	NA	NA	NA	NA	NA	NA	8.67E-05	2.62E-03	2.61E-03
	TPY	1.30E-05	3.93E-04	3.91E-04	NA	NA	NA	NA	NA	NA	1.30E-05	3.93E-04	3.91E-04
Cadmium													
	lb/hr	5.35E-06	1.62E-04	1.61E-04	NA	NA	NA	NA	NA	NA	5.35E-06	1.62E-04	1.61E-04
	TPY	8.03E-07	2.43E-05	2.42E-05	NA	NA	NA	NA	NA	NA	8.03E-07	2.43E-05	2.42E-05
Chromium													
	lb/hr	2.42E-05	7.32E-04	7.29E-04	NA	NA	NA	NA	NA	NA	2.42E-05	7.32E-04	7.29E-04
	TPY	3.63E-06	1.10E-04	1.09E-04	NA	NA	NA	NA	NA	NA	3.63E-06	1.10E-04	1.09E-04
Copper													
	lb/hr	1.43E-04	4.32E-03	4.30E-03	NA	NA	NA	NA	NA	NA	1.43E-04	4.32E-03	4.30E-03
	TPY	2.14E-05	6.47E-04	6.44E-04	NA	NA	NA	NA	NA	NA	2.14E-05	6.47E-04	6.44E-04
Vanadium													
	lb/hr	3.54E-05	1.07E-03	1.07E-03	NA	NA	NA	NA	NA	NA	3.54E-05	1.07E-03	1.07E-03
	TPY	5.32E-06	1.61E-04	1.60E-04	NA	NA	NA	NA	NA	NA	5.32E-06	1.61E-04	1.60E-04
Selenium													
	lb/hr	1.19E-05	3.61E-04	3.59E-04	NA	NA	NA	NA	NA	NA	1.19E-05	3.61E-04	3.59E-04
	TPY	1.79E-06	5.41E-05	5.39E-05	NA	NA	NA	NA	NA	NA	1.79E-06	5.41E-05	5.39E-05
Polycyclic Organic	lb/hr	1.42E-07	4.28E-06	4.27E-06	1.45E-05	1.40E-05	1.35E-05	0.00E+00	0.00E+00	0.00E+00	1.45E-05	1.40E-05	1.35E-05
Matter	TPY	2.13E-08	6.43E-07	6.40E-07	6.15E-05	5.91E-05	5.69E-05	0.00E+00	0.00E+00	0.00E+00	6.15E-05	5.98E-05	5.76E-05
Formaldehyde													
	lb/hr	2.07E-04	6.24E-03	6.21E-03	1.15E-03	1.11E-03	1.07E-03	0.00E+00	0.00E+00	0.00E+00	2.07E-04	6.24E-03	6.21E-03
	TPY	3.10E-05	9.36E-04	9.32E-04	4.87E-03	4.68E-03	4.51E-03	0.00E+00	0.00E+00	0.00E+00	4.90E-03	5.62E-03	5.44E-03

Note: NA = not applicable

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Table 4. Difference in Maximum Emissions for Additional Non-Regulated Pollutant for Tiger Bay Cogeneration Facility-Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	1.11E-05	3.37E-04	3.35E-04	NA	NA	NA	NA	NA	NA	1.11E-05	3.37E-04	3.35E-04
	TPY	1.67E-06	5.05E-05	5.03E-05	NA	NA	NA	NA	NA	NA	1.67E-06	5.05E-05	5.03E-05
Barium													
	lb/hr	9.95E-06	3.01E-04	3.00E-04	NA	NA	NA	NA	NA	NA	9.95E-06	3.01E-04	3.00E-04
	TPY	1.49E-06	4.51E-05	4.49E-05	NA	NA	NA	NA	NA	NA	1.49E-06	4.51E-05	4.49E-05
Cobalt													
	lb/hr	4.62E-06	1.40E-04	1.39E-04	NA	NA	NA	NA	NA	NA	4.62E-06	1.40E-04	1.39E-04
	TPY	6.93E-07	2.10E-05	2.09E-05	NA	NA	NA	NA	NA	NA	6.93E-07	2.10E-05	2.09E-05
Zinc													
	lb/hr	3.48E-04	1.05E-02	1.05E-02	NA	NA	NA	NA	NA	NA	3.48E-04	1.05E-02	1.05E-02
	TPY	5.23E-05	1.58E-03	1.57E-03	NA	NA	NA	NA	NA	NA	5.23E-05	1.58E-03	1.57E-03
Chlorine													
	lb/hr	-8.22E-04	-3.88E-04	-3.36E-04	NA	NA	NA	NA	NA	NA	-8.22E-04	-3.88E-04	-3.36E-04
	TPY	-1.23E-04	-5.81E-05	-5.04E-05	NA	NA	NA	NA	NA	NA	-1.23E-04	-5.81E-05	-5.04E-05

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Table 5. Percent Change in Maximum Emissions for Criteria Pollutants for Tiger Bay Cogeneration Facility- Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	-2.23%	-0.26%	0.00%	3.12%	1.69%	1.79%	0.00%	0.00%	0.00%	-2.17%	-0.25%	0.00%
TPY	-2.23%	-0.26%	0.00%	3.13%	1.69%	1.79%	0.00%	0.00%	0.00%	1.90%	1.16%	1.26%
Sulfur Dioxide:												
lb/hr	-1.87%	-0.91%	-0.85%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	-1.86%	-0.91%	-0.84%
TPY	-1.87%	-0.91%	-0.85%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	-0.25%	0.13%	0.16%
Nitrogen Oxides:												
lb/hr	-0.27%	1.81%	1.72%	-3.67%	1.75%	2.02%	0.00%	0.00%	0.00%	-0.27%	1.74%	1.65%
TPY	-0.27%	1.81%	1.72%	-3.67%	1.75%	2.02%	0.00%	0.00%	0.00%	-3.29%	1.64%	1.87%
Carbon Monoxide:												
lb/hr	-1.58%	0.87%	1.14%	3.79%	0.87%	0.92%	0.00%	0.00%	0.00%	-1.49%	0.82%	1.07%
TPY	-1.58%	0.87%	1.14%	3.79%	0.87%	0.92%	0.00%	0.00%	0.00%	2.37%	0.68%	0.73%
VOCs (as methane):												
lb/hr	-0.64%	0.87%	0.94%	0.77%	0.87%	0.92%	0.00%	0.00%	0.00%	-0.56%	0.75%	0.81%
TPY	-0.64%	0.87%	0.94%	0.77%	0.87%	0.92%	0.00%	0.00%	0.00%	0.49%	0.63%	0.66%
Lead:												
lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%

Note: NA = not applicable

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Table 6. Percent Change in Maximum Emissions of Other Regulated Pollutants for Tiger Bay Cogeneration Facility
Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Beryllium													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Mercury													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Fluoride													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Sulfuric Acid Mist	lb/hr	-1.87%	-0.91%	-0.85%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	-1.86%	-0.91%	-0.84%
	TPY	-1.87%	-0.91%	-0.85%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	-0.22%	0.15%	0.18%

Note: NA = not applicable

Table 7. Percent Change in Maximum Emissions of Non-Regulated Pollutants for Tiger Bay Cogeneration Facility-
Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Nickel													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Cadmium													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Chromium													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Copper													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Vanadium													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Selenium													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Polycyclic													
Organic	lb/hr	0.03%	1.00%	1.07%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	0.77%	0.83%	0.85%
Matter	TPY	0.03%	1.00%	1.07%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	0.76%	0.83%	0.85%
Formaldehyde													
	lb/hr	0.03%	1.00%	1.07%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	0.03%	0.99%	1.05%
	TPY	0.03%	1.00%	1.07%	0.82%	0.88%	0.91%	0.00%	0.00%	0.00%	0.67%	0.85%	0.88%

Note: NA = not applicable

Table 8. Percent Change in Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Base Load, Permit Application Compared to Revised Values

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Barium													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Cobalt													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Zinc													
	lb/hr	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
	TPY	0.03%	1.00%	1.07%	NA	NA	NA	NA	NA	NA	0.03%	1.00%	1.07%
Chlorine													
	lb/hr	-1.87%	-0.91%	-0.85%	NA	NA	NA	NA	NA	NA	-1.87%	-0.91%	-0.85%
	TPY	-1.87%	-0.91%	-0.85%	NA	NA	NA	NA	NA	NA	-1.87%	-0.91%	-0.85%

Table 9. Comparison of Maximum Emissions for Criteria Pollutants for Tiger Bay Cogeneration Facility-
Permit Application for GE and Westinghouse Turbines and Revised Westinghouse Data, Base Load

Pollutant	Permit Application GE PG7221(FA)			Permit Application Westinghouse 501F			Revised Data Westinghouse 501F		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Particulate:									
lb/hr	18.00	18.00	18.00	41.40	40.10	37.70	40.50	40.00	37.70
TPY	45.00	45.00	45.00	37.51	35.20	33.57	38.22	35.61	34.00
Sulfur Dioxide:									
lb/hr	100.02	88.87	82.11	91.35	87.31	82.32	89.65	86.52	81.63
TPY	36.82	33.05	30.74	35.24	32.46	30.52	35.15	32.50	30.57
Nitrogen Oxides:									
lb/hr	336.22	300.19	278.04	300.93	276.05	258.65	300.13	280.87	262.92
TPY	777.46	702.11	655.15	802.48	685.75	644.03	776.09	697.01	656.07
Carbon Monoxide:									
lb/hr	108.41	98.62	93.20	173.49	167.04	156.99	170.91	168.40	158.66
TPY	265.12	243.12	230.91	209.97	198.55	187.82	214.95	199.90	189.19
VOCs (as methane):									
lb/hr	10.40	9.48	9.40	21.76	21.18	20.06	21.64	21.34	20.22
TPY	25.63	24.46	23.66	49.53	45.29	44.66	49.77	45.57	44.95
Lead:									
lb/hr	1.65E-02	1.46E-02	1.35E-02	1.42E-02	1.37E-02	1.28E-02	1.42E-02	1.38E-02	1.29E-02
TPY	2.47E-03	2.19E-03	2.03E-03	2.13E-03	2.05E-03	1.91E-03	2.13E-03	2.07E-03	1.94E-03

Note: Based on firing natural gas and distillate oil for 8470 and 300 hours, respectively.
Total emissions include emissions from the combustion turbine and duct burner.

Table 10. Comparison of Maximum Emissions of Other Regulated Pollutants for Tiger Bay Cogeneration Facility-Permit Application for GE and Westinghouse Turbines and Revised Westinghouse Data, Base Load

Pollutant		Maximum Emissions			Maximum Emissions			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic										
	lb/hr	7.77E-03	6.90E-03	6.37E-03	6.70E-03	6.45E-03	6.02E-03	6.70E-03	6.52E-03	6.09E-03
	TPY	1.17E-03	1.04E-03	9.56E-04	1.01E-03	9.68E-04	9.04E-04	1.01E-03	9.78E-04	9.13E-04
Beryllium										
	lb/hr	4.62E-03	4.11E-03	3.79E-03	3.99E-03	3.84E-03	3.59E-03	3.99E-03	3.88E-03	3.62E-03
	TPY	6.94E-04	6.16E-04	5.69E-04	5.98E-04	5.76E-04	5.38E-04	5.98E-04	5.82E-04	5.44E-04
Mercury										
	lb/hr	5.55E-03	4.93E-03	4.55E-03	4.79E-03	4.61E-03	4.30E-03	4.79E-03	4.66E-03	4.35E-03
	TPY	8.32E-04	7.39E-04	6.83E-04	7.18E-04	6.91E-04	6.45E-04	7.18E-04	6.98E-04	6.52E-04
Fluoride										
	lb/hr	6.02E-02	5.35E-02	4.94E-02	5.19E-02	5.00E-02	4.67E-02	5.19E-02	5.05E-02	4.72E-02
	TPY	9.03E-03	8.02E-03	7.41E-03	7.79E-03	7.50E-03	7.00E-03	7.79E-03	7.57E-03	7.08E-03
Sulfuric Acid Mist	lb/hr	1.23E+01	1.09E+01	1.01E+01	1.12E+01	1.07E+01	1.01E+01	1.10E+01	1.06E+01	1.00E+01
	TPY	4.65E+00	4.18E+00	3.89E+00	4.46E+00	4.10E+00	3.86E+00	4.45E+00	4.11E+00	3.86E+00

Note: Based on firing natural gas and distillate oil for 8470 and 300 hours, respectively.
Total emissions include emissions from the combustion turbine and duct burner.

Table 11. Comparison of Maximum Emissions of Non-Regulated Pollutants for Tiger Bay Cogeneration Facility-Permit Application for GE and Westinghouse Turbines and Revised Westinghouse Data, Base Load

Pollutant		Maximum Emissions			Maximum Emissions			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese										
	lb/hr	2.59E-02	2.30E-02	2.12E-02	2.23E-02	2.15E-02	2.01E-02	2.23E-02	2.17E-02	2.03E-02
	TPY	3.88E-03	3.45E-03	3.19E-03	3.35E-03	3.23E-03	3.01E-03	3.35E-03	3.26E-03	3.04E-03
Nickel										
	lb/hr	3.14E-01	2.79E-01	2.58E-01	2.71E-01	2.61E-01	2.44E-01	2.71E-01	2.64E-01	2.46E-01
	TPY	4.72E-02	4.19E-02	3.87E-02	4.07E-02	3.92E-02	3.66E-02	4.07E-02	3.96E-02	3.70E-02
Cadmium										
	lb/hr	1.94E-02	1.73E-02	1.59E-02	1.68E-02	1.61E-02	1.51E-02	1.68E-02	1.63E-02	1.52E-02
	TPY	2.91E-03	2.59E-03	2.39E-03	2.51E-03	2.42E-03	2.26E-03	2.51E-03	2.44E-03	2.28E-03
Chromium										
	lb/hr	8.79E-02	7.80E-02	7.21E-02	7.58E-02	7.30E-02	6.81E-02	7.58E-02	7.37E-02	6.89E-02
	TPY	1.32E-02	1.17E-02	1.08E-02	1.14E-02	1.09E-02	1.02E-02	1.14E-02	1.11E-02	1.03E-02
Copper										
	lb/hr	5.18E-01	4.60E-01	4.25E-01	4.47E-01	4.30E-01	4.02E-01	4.47E-01	4.35E-01	4.06E-01
	TPY	7.77E-02	6.90E-02	6.37E-02	6.70E-02	6.45E-02	6.02E-02	6.70E-02	6.52E-02	6.09E-02
Vanadium										
	lb/hr	1.29E-01	1.14E-01	1.05E-01	1.11E-01	1.07E-01	9.97E-02	1.11E-01	1.08E-01	1.01E-01
	TPY	1.93E-02	1.71E-02	1.58E-02	1.66E-02	1.60E-02	1.50E-02	1.66E-02	1.62E-02	1.51E-02
Selenium										
	lb/hr	4.33E-02	3.85E-02	3.55E-02	3.74E-02	3.60E-02	3.36E-02	3.74E-02	3.63E-02	3.40E-02
	TPY	6.50E-03	5.77E-03	5.33E-03	5.60E-03	5.40E-03	5.04E-03	5.61E-03	5.45E-03	5.09E-03
Polycyclic										
Organic	lb/hr	1.91E-03	1.73E-03	1.61E-03	1.88E-03	1.69E-03	1.59E-03	1.90E-03	1.71E-03	1.60E-03
Matter	TPY	8.17E-03	7.38E-03	6.90E-03	8.05E-03	7.25E-03	6.80E-03	8.11E-03	7.31E-03	6.86E-03
Formaldehyde										
	lb/hr	7.58E-01	6.74E-01	6.23E-01	6.55E-01	6.31E-01	5.90E-01	6.55E-01	6.37E-01	5.96E-01
	TPY	7.53E-01	6.79E-01	6.33E-01	7.29E-01	6.62E-01	6.21E-01	7.34E-01	6.68E-01	6.26E-01

Note: Based on firing natural gas and distillate oil for 8470 and 300 hours, respectively.
Total emissions include emissions from the combustion turbine and duct burner.

Table 12. Comparison of Maximum Emissions for Additional Non-Regulated Pollutant for Tiger Bay Facility-
Permit Application for GE and Westinghouse Turbines and Revised Westinghouse Data, Base Load

Pollutant		Maximum Emissions			Maximum Emissions			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony										
	lb/hr	4.04E-02	3.59E-02	3.32E-02	3.49E-02	3.36E-02	3.13E-02	3.49E-02	3.39E-02	3.17E-02
	TPY	6.06E-03	5.38E-03	4.97E-03	5.23E-03	5.03E-03	4.70E-03	5.23E-03	5.09E-03	4.75E-03
Barium										
	lb/hr	3.61E-02	3.21E-02	2.96E-02	3.11E-02	3.00E-02	2.80E-02	3.12E-02	3.03E-02	2.83E-02
	TPY	5.42E-03	4.81E-03	4.44E-03	4.67E-03	4.50E-03	4.20E-03	4.67E-03	4.54E-03	4.25E-03
Cobalt										
	lb/hr	1.68E-02	1.49E-02	1.38E-02	1.45E-02	1.39E-02	1.30E-02	1.45E-02	1.41E-02	1.31E-02
	TPY	2.51E-03	2.23E-03	2.06E-03	2.17E-03	2.09E-03	1.95E-03	2.17E-03	2.11E-03	1.97E-03
Zinc										
	lb/hr	1.26E+00	1.12E+00	1.04E+00	1.09E+00	1.05E+00	9.80E-01	1.09E+00	1.06E+00	9.91E-01
	TPY	1.90E-01	1.68E-01	1.56E-01	1.64E-01	1.57E-01	1.47E-01	1.64E-01	1.59E-01	1.49E-01
Chlorine										
	lb/hr	4.99E-02	4.43E-02	4.09E-02	4.41E-02	4.24E-02	3.96E-02	4.32E-02	4.21E-02	3.93E-02
	TPY	7.48E-03	6.64E-03	6.14E-03	6.61E-03	6.37E-03	5.94E-03	6.49E-03	6.31E-03	5.89E-03

Note: Based on firing natural gas and distillate oil for 8470 and 300 hours, respectively.
Total emissions include emissions from the combustion turbine and duct burner.

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August 26, 1992

RECEIVED

AUG 27 1992

Division of Air
Resources Management

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

Re: Central Florida Power Limited Partnership
Tiger Bay (formerly Central Florida) cogeneration plant
PSD-FL-190
AC 53-214903

Dear Mr. Fancy:

This correspondence presents the information requested by the Department's July 14, 1992, letter. The responses have been prepared based on phone conversations held on July 15, 1992, with Mr. Mirza Baig, and subsequent discussions held with Mr. Cleve Holladay and Mr. John Glunn.

1. COMMENT: Section 1-1 states the electrical output of the cogeneration facility is 206 MW. The gas turbine (GT) is rated at 147 MW and the duct burner is rated at 74 MW, giving a total of 221 MW. What is the maximum electrical output you would like to be permitted for this facility?

   RESPONSE: The maximum electrical output of the cogeneration facility is 258 MW (GE machine) and 246 MW (Westinghouse machine), based on the following conditions: fuel oil firing and an ambient temperature of 27°F. The breakdown of the maximum electrical output for both machines for fuel oil is as follows:

	Maximum Rated Electrical Output (MW)	
Fuel/Unit	GE	Westinghouse
Combustion Turbine	184	172
Steam Turbine	74	74

2. COMMENT: According to Section 1-1, two types of advanced GTs are being considered for this project. The Department must know the exact type of gas turbine you propose to install so that a BACT determination can be made. Accordingly, please submit detailed information of the unit selected. We will also need any available stack test data for that unit.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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RESPONSE: The combustion turbine for the project has not been selected. The candidate turbines are currently being evaluated for performance and commercial terms. The air construction application for the project was based on the advanced class of turbines, and performance and emissions are similar for the two turbines under consideration. The information on both turbines is presented in Attachment 1. The information presented in the application was based on performance and emissions characteristics that enveloped these two turbines. Since the performance and emission characteristics are similar for the turbines under consideration, a decision regarding BACT would not be substantially different regardless of which turbine was selected. A similar decision was made by the Department in the BACT determination for the Hardee Power Station. In that project, four combustion turbines were proposed by the applicant, with the Department's BACT determination made on an envelope of performance and emission characteristics.

3. COMMENT: What is the maximum sulfur content of the natural gas you propose to burn? Provide a copy of any sulfur content guarantee that you may have from the supplier.

   RESPONSE: The maximum sulfur content of the natural gas proposed in the application was 1 grain of sulfur per 100 cubic feet (1 gr/100 cf). This was based on an evaluation of 9 months of sulfur content data supplied by Florida Gas Transmission (FGT). FGT is the only supplier of pipeline natural gas in Florida. The results of the evaluation are presented in Table 1. As shown in this table, the average sulfur content of natural gas was 0.43 gr/100 cf. A 130 percent contingency was used to develop the proposed emission rate of 1 gr/100 cf from the average sulfur content of 0.43 gr/100 cf reported by FGT in natural gas and would statistically account for potentially higher sulfur contents. Sulfur content information supplied by FGT for four sample analyses performed in April and May 1992 indicated a maximum sulfur content of 0.4 gr/100 cf which is within the previously supplied data (see Attachment 2).

   There is no guaranteed sulfur content for natural gas that is supplied by FGT.

4. COMMENT: Submit an updated process flow diagram showing steam turbine and volumetric air flow rates.

   RESPONSE: Updated process flow diagrams showing the steam turbine and the mass energy balance around the steam turbine and gas turbine are presented in Attachment 3 for natural gas and fuel oil firing.

5. COMMENT: In Section 4-12, Table 4-2, the emissions (25 ppmvd) for advance GT with dry low-NO_x technology appears to be incorrect. Also, Table 4-2 should state the turbine size on which these figures are based.

   RESPONSE: The 25 ppmvd listed for the dry low-NO_x technology in both the conventional and advanced machines is correct. This is the actual level that would be emitted from each machine. The 22.5 ppmvd listed on page 4-11 of the report is for the advanced machine when the emission rate is adjusted based on the same amount of generation (i.e., megawatt-hours) as a conventional gas turbine. As described in the preceding paragraph, the advanced

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machine is more efficient and will result in lower NO_x emissions for each megawatt generated. This comparison would be analogous to the amount of particulate per ton of clinker produced by a cement plant.

The sizes of the turbines in Table 4-2 are: conventional--82 MW gas and 84 MW oil; advanced--147.1 MW gas and 159.2 MW oil [for GE PG7221(FA) machine at ambient temperature of 72 °F].

6. COMMENT: Submit all emission calculations and not just an example calculation. These emission calculations shall be based on the selected turbine for this project.

   RESPONSE: The detailed emission calculations for the turbine proposed for this project are presented in Attachment 4 to this letter.

7. COMMENT: What is the expected maximum ambient concentrations for the metals emitted?

   RESPONSE: The expected maximum ambient concentrations for toxic air pollutants, including metals, are presented in Table 7-5, page 7-9, in the PSD analysis that supports the air construction permit application. Based on the results presented in the table, the highest predicted impacts were below the no-threat levels for all pollutants and averaging times.

8. COMMENT: Please provide an air quality related analysis (AQRV) of the impact this project will have on the Chassahowitzka National Wilderness Area (CNWA) for the pollutant NO_2. The AQRV analysis includes impacts to soil, vegetation, and wildlife. This analysis also includes an assessment of impacts to the aquatic environment. Since the modeling information already provided with this application shows that the predicted NO_2 impact at the CNWA Class I area is less than the National Park Service (NPS) recommended significance level, the NPS has verbally stated that only a literature review is needed in order to comply with the AQRV analysis requirement.

   RESPONSE: KBN has performed air quality analyses to determine the Prevention of Significant Deterioration (PSD) Class I increment consumption and Air Quality Related Values (AQRV) Analyses for the Chassahowitzka National Wilderness Area (NWA) due to emissions from the Tiger Bay cogeneration facility. The facility is located approximately 120 km from the closest part of the Chassahowitzka National Wilderness Area (NWA), a PSD Class I area. The proposed facility alone had a maximum predicted annual average nitrogen dioxide (NO_2) impact of 0.014 $\mu g/m^3$, which is less than the National Park Service (NPS) significant impact level of 0.025 $\mu g/m^3$.

   Based on verbal communications between the Florida Department of Environmental Regulation (FDER) and NPS, the AQRV analyses for the PSD Class I area of the Chassahowitzka NWA need only address the impacts of increased NO_2 emissions for this project.

   The Chassahowitzka NWA is characterized by vegetation which includes flatwoods, brackish-water, marine, and halophytic terrestrial species. Predominant tree species are slash pine,

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laurel oak, sweetgum, and palm. Other plants in the preserve include needlegrass rush, seashore saltgrass, marsh hay, and red mangrove. NO_2 concentrations can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru et al., 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

By comparison of published toxicity values for NO_2 exposure to short-term (i.e., 1-, 3-, and 8-hour averaging times) and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the preserve can be examined for both acute and chronic exposure situations, respectively. The 1-, 3-, and 8-hour estimated NO_2 concentrations at the point of maximum impact are 3.65, 2.14, and 1.00 $\mu g/m^3$, respectively. These concentrations are approximately 6.7×10^{-5} to 9.6×10^{-4} of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the annual estimated NO_2 concentration at the point of maximum impact in the preserve (0.014 $\mu g/m^3$) is 3.5×10^{-6} to 7.0×10^{-6} of the levels that caused minimal yield loss and chlorosis in plant tissue.

The majority of the soil in the Class I area is classified as Weekiwachee--Durbin muck. This is an euic, hyperthermic typic sufihemist that is characterized by high levels of sulfur and organic matter. This soil is flooded daily with the advent of high tide, and the pH ranges between 6.1 and 7.8. The upper level of this soil may contain as much as 4 percent sulfur (USDA, 1991).

The greatest threat to soils from increased NO_2 deposition is a decrease in pH or an increase of sulfur to levels considered unnatural or potentially toxic. Although ground deposition was not calculated, it is evident that the amount of NO_2 deposited would be inconsequential in light of the inherent sulfur content. The regular flooding of these soils by the Gulf of Mexico regulates the pH, and any rise in acidity in the soil would be buffered by this activity.

The predicted NO_2 concentrations are well below the lowest observed effects levels in animals (Newman and Schreiber, 1988). Given these conditions, the proposed source's emissions pose no risk to wildlife. Because predicted levels are below those known to cause effects to vegetation, there is also no risk.

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References

Heck, W.W. and D.T. Tingey. 1979. Nitrogen Dioxide: Time-Concentration Model to Predict Acute Foliar Injury. EPA-600/3-79-057, U.S. Environmental Protection Agency, Corvallis, OR.

Matsumaru, T., T. Yoneyama, T. Totsuka, and K. Shiratori. 1979. Absorption of Atmospheric NO_2 by Plants and Soils. Soil Sci. Plant Nutr. 25:255-265.

Newman, J.R. and Schreiber. 1988. Air Pollution and Wildlife Toxicology. Environmental Toxicology and Chemistry 7:381-390.

U.S. Department of Agriculture. 1991. Surveys of Hernando and Citrus Counties, Florida. USDA Soil Conservation Service in cooperation with University of Florida, Institute of Food and Agricultural Sciences, Agricultural Experiment Stations, and Soil Science Department.

Zahn, R. 1975. Gassing Experiments with NO_2 in Small Greenhouses. Staub Reinhalt. Luft 35:194-196.

9. COMMENT: Section 4.3.1.2, page 4-10, states that "While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustion design." How much additional thermal NO_x is generated due to higher temperature?

   RESPONSE: The increased thermal NO_x emissions, due to the higher firing temperature of the advanced combustion turbine, is about 20 percent higher than a conventional turbine when firing natural gas (from Table 4-2, 150 ppmvd, conventional, compared to 179 ppmvd, advanced) and about 13 percent higher than a conventional turbine when firing oil (from Table 4-2, 245 ppmvd, conventional, compared to 276 ppmvd, advanced).

10. COMMENT: On page 4-3, the estimated cost of SCR is reported to be about $7,400 per ton of NO_x removed and it exceeds $10,000 per ton of pollutant removed when the net emissions of all pollutants (exclusive of CO_2) are considered. Provide us with the names and addresses of all manufacturers that were contacted while developing capital and annualized cost estimates for this project.

    RESPONSE: The cost for SCR was obtained from a database developed by KBN from this and other projects. The manufacturers contacted were:

    Steuler International Corporation
    P.O. Box 38
    Mertztown, PA 19539-0038
    215-682-7171

    Hitachi Zosen U.S.A. Ltd.
    150 East 52 nd Street
    New York, NY 10022
    212-355-5650

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Mitsubishi International Corporation
2 Houston Center, Suite 3800
Houston, TX 77010
713-652-9200

W. R. Grace & Co.
P.O. Box 2117
Baltimore, MD 21203-2117
410-659-9000

Norton Company
P.O. Box 350
Arkon, OH 44309-0350
216-673-5860

11. COMMENT (via July 15, 1992, telephone conversation): Provide a large-scale site plan similar to Figure 2-2 of the air permit application.

    RESPONSE: A full-scale revised plot plan is included in Attachment 5.

12. COMMENT (via July 15, 1992, telephone conversation): Please provide a diagram indicating the proposed location of the sample ports for source sampling purposes. Show these locations with respect to the proposed stack and HRSG unit.

    RESPONSE: The stack sample port location is depicted in Figure 1. The sample port will be accessible by ladder from the top of the HRSG to a platform assembly near the port location.

Submittal of this information should clarify all questions raised by the Department in the completeness determination for this project. Please call me at 904-331-9000 if there are any further questions on the material submitted.

Sincerely,

Robert C. McCann Jr.
for

Kennard F. Kosky, P.E.
President

Enclosures
KFK/dmm

cc: Mirza Baig, FDER
    Robert I. Taylor, Central Florida Power, L.P.
    Robert Chatham, Destec Engineering, Inc.
    File (2)

Table 1. Sulfur Content, Heat Content, and SO_2 Emission Factors for Natural Gas

Date	Sulfur Content (gr/100 cf)	Heat Content (Btu)	SO_2 Emission Factor (lb/10^6 Btu)	SO_2 Emission Factor (lb/10^6 cf)
2/6/90	0.30	1,031	0.00083	0.857
2/13/90	0.05	1,028	0.00014	0.143
2/20/90	0.35	1,025	0.00098	1.000
2/27/90	0.45	1,024	0.00126	1.286
3/6/90	0.45	1,025	0.00125	1.286
3/13/90	0.30	1,026	0.00084	0.857
3/20/90	0.35	1,026	0.00097	1.000
3/27/90	0.35	1,025	0.00098	1.000
4/3/90	0.60	1,026	0.00167	1.714
4/10/90	0.25	1,022	0.00070	0.714
4/17/90	0.40	1,026	0.00111	1.143
4/24/90	0.30	1,022	0.00084	0.857
5/1/90	0.40	1,020	0.00112	1.143
5/8/90	0.25	1,034	0.00069	0.714
5/15/90	0.20	1,023	0.00056	0.571
6/5/90	0.45	1,020	0.00126	1.286
6/12/90	0.40	1,018	0.00112	1.143
6/19/90	0.70	1,017	0.00197	2.000
6/26/90	0.45	1,019	0.00126	1.286
7/3/90	0.55	1,022	0.00154	1.571
7/10/90	0.35	1,022	0.00098	1.000
7/17/90	0.45	1,021	0.00126	1.286
7/30/90	0.30	1,021	0.00084	0.857
8/7/90	0.50	1,024	0.00140	1.429
8/14/90	0.45	1,022	0.00126	1.286
8/21/90	0.40	1,022	0.00112	1.143
8/28/90	0.70	1,022	0.00196	2.000
9/4/90	0.55	1,029	0.00153	1.571
9/11/90	0.40	1,025	0.00111	1.143
9/18/90	0.45	1,026	0.00125	1.286
9/25/90	0.40	1,026	0.00111	1.143
10/2/90	0.45	1,029	0.00125	1.286
10/9/90	0.45	1,025	0.00125	1.286
10/16/90	0.70	1,028	0.00195	2.000
10/28/90	0.80	1,024	0.00223	2.286
Average:	0.43	1,024	0.00119	1.216
Maximum:	0.80	1,034	0.00223	2.286
Minimum:	0.05	1,017	0.00014	0.143
Std. Dev.	0.15	4	0.00042	0.427

Source: Florida Gas Transmission Company, 1990.

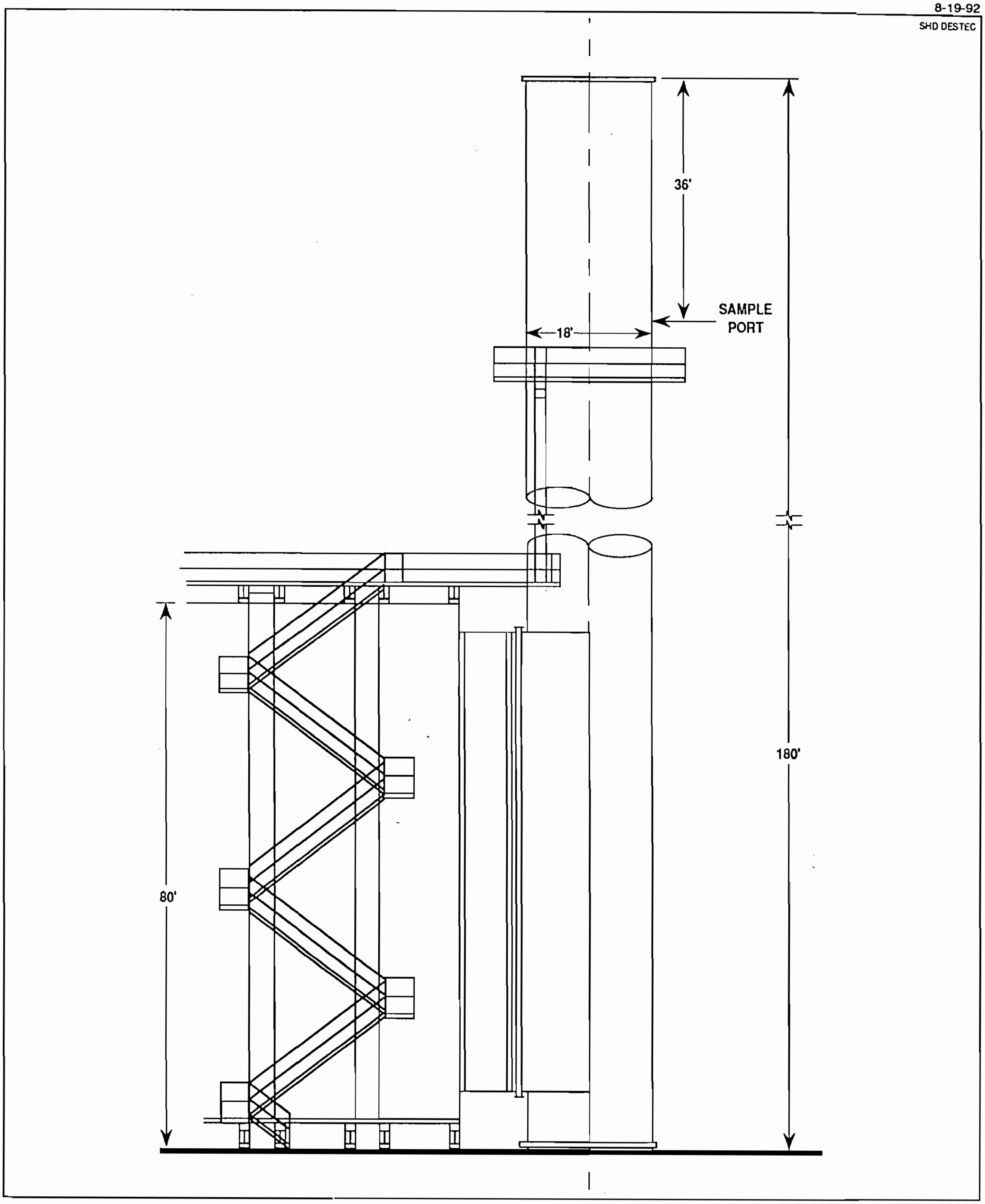

Figure 1 TIGER BAY CONCEPTUAL DRAWING OF STACK AND ADJOINING STRUCTURE

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ATTACHMENT 1

MANUFACTURER'S DESIGN SPECIFICATIONS FOR THE COMBUSTION TURBINE

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	90%	80%	70%	60%
AMBIENT TEMP.	– Deg F .	27	27	27	27	27
OUTPUT	– kW	170700.	153200.	135300.	119900.	101400.
HEAT RATE (LHV)	– Btu/kWh	9460.	9770.	10240.	10770.	11600.
HEAT CONS. (LHV) X10–6	– Btu/h	1614.8	1496.8	1385.5	1291.3	1176.2
EXHAUST FLOW X10–3	– lb/h	3582.0	3228.0	2958.0	2744.0	2521.0
EXHAUST TEMP	– Deg F.	1078.	1118.	1150.	1177.	1200.
EXHAUST ENERGY X10–6	– Btu/h	976.4	922.1	875.5	836.9	788.6
NOX	– ppmvd @ 15% O2	25.	25.	25.	25.	25.
NOX AS NO2	– lb/h	162	149.	138.	128.	116.
CO	– ppmvd	15.	*	*	*	*
CO	– lb/h	49.	*	*	*	*
UHC	– ppmvw	7.	*	*	*	*
UHC	– lb/h	14.	*	*	*	*
VOC	– ppmvw	1.4	*	*	*	*
VOC	– lb/h	2.8	*	*	*	*
PART	– lb/h	9.0	9.0	9.0	9.0	9.0
EXHAUST ANALYSIS % VOL.						
ARGON		0.90	0.90	0.90	0.90	0.90
NITROGEN		75.04	74.97	74.95	74.95	74.98
OXYGEN		12.71	12.52	12.46	12.46	12.56
CARBON DIOXIDE		3.74	3.83	3.85	3.85	3.81
WATER		7.61	7.78	7.84	7.84	7.75

SITE CONDITIONS		
ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	40
FUEL TYPE	–	METHANE
FUEL LHV	– Btu/lb	21515
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
COMPRESSOR BLEED HEAT IS USED FOR 70% AND 60% PART LOAD OPERATION.
APPROXIMATELY 10% OF THE VOC'S ARE NON–METHANE AND ETHANE.
* DATA NOT AVAILABLE
IPS–8707
JPT 3/19/92

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	90%	80%	70%	60%
AMBIENT TEMP.	– Deg F .	64	64	64	64	64
OUTPUT	– kW	151900.	136000.	124400.	106500.	89900.
HEAT RATE (LHV)	– Btu/kWh	9750.	10060.	10340.	11070.	11860.
HEAT CONS. (LHV) X10–6	– Btu/h	1481.0	1368.2	1286.3	1179.0	1066.2
EXHAUST FLOW X10–3	– lb/h	3322.0	3010.0	2810.0	2595.0	2413.0
EXHAUST TEMP	– Deg F.	1110.	1145.	1168.	1195.	1200.
EXHAUST ENERGY X10–6	– Btu/h	911.3	856.4	816.8	773.9	721.3
NOX	– ppmvd @ 15% O2	25.	25.	25.	25.	25.
NOX AS NO2	– lb/h	149	137.	129.	118.	107.
CO	– ppmvd	15.	*	*	*	*
CO	– lb/h	45.	*	*	*	*
UHC	– ppmvw	7.	*	*	*	*
UHC	– lb/h	13.	*	*	*	*
VOC	– ppmvw	1.4	*	*	*	*
VOC	– lb/h	2.6	*	*	*	*
PART	– lb/h	9.0	9.0	9.0	9.0	9.0
EXHAUST ANALYSIS % VOL.						
ARGON		0.89	0.89	0.88	0.88	0.89
NITROGEN		74.04	73.98	73.97	73.98	74.05
OXYGEN		12.56	12.41	12.35	12.41	12.62
CARBON DIOXIDE		3.68	3.75	3.78	3.75	3.65
WATER		8.83	8.97	9.02	8.98	8.79

SITE CONDITIONS		
ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	78
FUEL TYPE	–	METHANE
FUEL LHV	– Btu/lb	21515
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
COMPRESSOR BLEED HEAT IS USED FOR 70% AND 60% PART LOAD OPERATION.
APPROXIMATELY 10% OF THE VOC'S ARE NON–METHANE AND ETHANE.
* DATA NOT AVAILABLE
IPS–8707
JPT 3/19/92

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	90%	80%	70%	60%
AMBIENT TEMP.	– Deg F	72	72	72	72	72
OUTPUT	– kW	147100.	131800.	120500.	103100.	86800.
HEAT RATE (LHV)	– Btu/kWh	9860.	10210.	10550.	11340.	12220.
HEAT CONS. (LHV) X10–6	– Btu/h	1450.4	1345.7	1271.3	1169.2	1060.7
EXHAUST FLOW X10–3	– lb/h	3262.0	2960.0	2768.0	2560.0	2383.0
EXHAUST TEMP	– Deg F.	1117.	1151.	1173.	1199.	1200.
EXHAUST ENERGY X10–6	– Btu/h	898.1	849.0	815.5	776.0	726.5
NOX	– ppmvd @ 15% O2	25.	25.	25.	25.	25.
NOX AS NO2	– lb/h	145	134.	126.	116.	105.
CO	– ppmvd	15.	*	*	*	*
CO	– lb/h	44.	*	*	*	*
UHC	– ppmvw	7.	*	*	*	*
UHC	– lb/h	13.	*	*	*	*
VOC	– ppmvw	1.4	*	*	*	*
VOC	– lb/h	2.6	*	*	*	*
PART	– lb/h	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.	BASE	90%	80%	70%	60%
ARGON	0.89	0.88	0.89	0.87	0.88
NITROGEN	73.73	73.68	73.67	73.68	73.76
OXYGEN	12.51	12.37	12.32	12.39	12.63
CARBON DIOXIDE	3.66	3.73	3.75	3.72	3.61
WATER	9.21	9.34	9.38	9.34	9.12

SITE CONDITIONS		
ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	75
FUEL TYPE	–	METHANE
FUEL LHV	– Btu/lb	21515
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
COMPRESSOR BLEED HEAT IS USED FOR 70% AND 60% PART LOAD OPERATION.
APPROXIMATELY 10% OF THE VOC'S ARE NON–METHANE AND ETHANE.
* DATA NOT AVAILABLE
IPS–8707
JPT 3/19/92

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	90%	80%	70%	60%
AMBIENT TEMP.	– Deg F .	79	79	79	79	79
OUTPUT	– kW	142700.	127900.	116500.	99500.	83900.
HEAT RATE (LHV)	– Btu/kWh	9970.	10330.	10700.	11510.	12390.
HEAT CONS. (LHV) X10–6	– Btu/h	1422.7	1321.2	1246.6	1145.2	1039.5
EXHAUST FLOW X10–3	– lb/h	3202.0	2910.0	2725.0	2524.0	2352.0
EXHAUST TEMP	– Deg F.	1124.	1157.	1179.	1200.	1200.
EXHAUST ENERGY X10–6	– Btu/h	886.3	838.6	805.2	765.1	715.8
NOX	– ppmvd @ 15% O2	25.	25.	25.	25.	25.
NOX AS NO2	– lb/h	143	132.	124.	114.	103.
CO	– ppmvd	15.	*	*	*	*
CO	– lb/h	43.	*	*	*	*
UHC	– ppmvw	7.	*	*	*	*
UHC	– lb/h	13.	*	*	*	*
VOC	– ppmvw	1.4	*	*	*	*
VOC	– lb/h	2.6	*	*	*	*
PART	– lb/h	9.0	9.0	9.0	9.0	9.0
EXHAUST ANALYSIS % VOL.						
ARGON		0.87	0.88	0.87	0.88	0.87
NITROGEN		73.07	73.02	73.01	73.02	73.10
OXYGEN		12.36	12.22	12.19	12.28	12.52
CARBON DIOXIDE		3.65	3.71	3.73	3.68	3.58
WATER		10.05	10.17	10.20	10.14	9.93

SITE CONDITIONS

ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	86
FUEL TYPE	–	METHANE
FUEL LHV	– Btu/lb	21515
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
COMPRESSOR BLEED HEAT IS USED FOR 70 AND 60% PART LOAD OPERATION
APPROXIMATELY 10% OF THE VOC'S ARE NON–METHANE AND ETHANE.
* DATA NOT AVAILABLE
IPS–8707
JPT 3/19/92

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	90%	80%	70%	60%
AMBIENT TEMP.	– Deg F .	97	97	97	97	97
OUTPUT	– kW	131800.	118400.	106800.	90900.	77100.
HEAT RATE (LHV)	– Btu/kWh	10230.	10600.	11070.	11890.	12780.
HEAT CONS. (LHV) X10–6	– Btu/h	1348.3	1255.0	1182.3	1080.8	985.3
EXHAUST FLOW X10–3	– lb/h	3077.0	2808.0	2640.0	2454.0	2293.0
EXHAUST TEMP	– Deg F.	1140.	1170.	1190.	1200.	1200.
EXHAUST ENERGY X10–6	– Btu/h	851.5	807.0	776.1	732.0	686.5
NOX	– ppmvd @ 15% O2	25.	25.	25.	25.	25.
NOX AS NO2	– lb/h	135	125.	118.	107.	97.
CO	– ppmvd	15.	*	*	*	*
CO	– lb/h	41.	*	*	*	*
UHC	– ppmvw	7.	*	*	*	*
UHC	– lb/h	12.	*	*	*	*
VOC	– ppmvw	1.4	*	*	*	*
VOC	– lb/h	2.4	*	*	*	*
PART	– lb/h	9.0	9.0	9.0	9.0	9.0
EXHAUST ANALYSIS % VOL.						
ARGON		0.88	0.87	0.87	0.88	0.89
NITROGEN		73.13	73.09	73.10	73.13	73.20
OXYGEN		12.48	12.36	12.37	12.52	12.74
CARBON DIOXIDE		3.60	3.66	3.65	3.58	3.48
WATER		9.91	10.02	10.01	9.89	9.70

SITE CONDITIONS

ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	48
FUEL TYPE	–	METHANE
FUEL LHV	– Btu/lb	21515
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
COMPRESSOR BLEED HEAT IS USED FOR 70% AND 60% PART LOAD OPERATION.
APPROXIMATELY 10% OF THE VOC'S ARE NON–METHANE AND ETHANE.
* DATA NOT AVAILABLE
IPS–8707
JPT 3/19/92

DESTEC - GATOR COGEN
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ESTIMATED PERFORMANCE - PG7221(FA)

LOAD CONDITION		BASE	70%
AMBIENT TEMP.	- Deg F.	27	27
OUTPUT	- kW	183700.	129200.
HEAT RATE (LHV)	- Btu/kWh	10070.	11430.
HEAT RATE (HHV)	- Btu/kWh	10674.	12115.
HEAT CONS. (LHV) X10-6	- Btu/h	1849.9	1476.8
EXHAUST FLOW X10-3	- lb/h	3743.0	2837.0
EXHAUST TEMP	- Deg F.	1060.	1166.
EXHAUST HEAT X10-6	- Btu/h	1021.8	876.8
WATER FLOW	- lb/h	135390.	105120.

NOX	- ppmvd @ 15% 02	42.	42.
NOX AS NO2	- lb/h	327.	258.
CO	- ppmvd	30.	*
CO	- lb/h	98.	*
UHC	- ppmvw	7.	*
UHC	- lb/h	15.	*
VOC	- ppmvw	3.5	*
VOC	- lb/h	7.5	*
SO2	- ppmvw	11.	12.
SO2	- lb/h	95.	76.
SO3	- ppmvw	1.	1.
SO3	- lb/h	6.	5.
SULFUR MIST	- lb/h	10.	8.
PART	- lb/h	17.0	17.0

EXHAUST ANALYSIS % VOL.

ARGON	0.86	0.85
NITROGEN	71.27	71.08
OXYGEN	10.96	10.57
CARBON DIOXIDE	5.32	5.54
WATER	11.59	11.96

SITE CONDITIONS
****

ELEVATION	- ft.	160
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	4
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	40
FUEL TYPE	-	DISTILLATE
FUEL LHV	- Btu/lb	18550
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% 02 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
DISTILLATE FUEL IS ASSUMED TO HAVE .015% FUEL BOUND NITROGEN, OR LESS.
FBN AMOUNTS GREATER THAN .015% WILL ADD TO THE REPORTED NOx VALUE.
SULFUR EMISSIONS BASED ON .05 WT% SULFUR CONTENT IN THE FUEL.

* DATA NOT AVAILABLE
COMPRESSOR BLEED HEAT USED FOR PART LOAD OPERATION.

SULFUR EMISSIONS ARE BASED ON A TOTAL FUEL SULFUR CONTENT OF 0.0[illegible]

IPS-8707
IPT 5/6/92

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	70%
AMBIENT TEMP.	– Deg F.	72	72
OUTPUT	– kW	159200.	111000.
HEAT RATE (LHV)	– Btu/kWh	10320.	11800.
HEAT CONS. (LHV) X10–6	– Btu/h	1642.9	1309.8
EXHAUST FLOW X10–3	– lb/h	3390.0	2619.0
EXHAUST TEMP	– Deg F.	1102.	1192.
EXHAUST HEAT X10–6	– Btu/h	932.2	801.6
WATER FLOW	– lb/h	107070.	80490.
NOX	– ppmvd @ 15% O2	42.	42.
NOX AS NO2	– lb/h	290.	229.
CO	– ppmvd	30.	*
CO	– lb/h	89.	*
UHC	– ppmvw	7.	*
UHC	– lb/h	13.	*
VOC	– ppmvw	3.5	*
VOC	– lb/h	6.5	*
PART	– lb/h	17.0	17.0

EXHAUST ANALYSIS % VOL.		
ARGON	0.86	0.86
NITROGEN	70.59	70.63
OXYGEN	10.95	10.81
CARBON DIOXIDE	5.21	5.31
WATER	12.40	12.40

SITE CONDITIONS		
ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	75
FUEL TYPE	–	DISTILLATE
FUEL LHV	– Btu/lb	18550
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(I).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
DISTILLATE FUEL IS ASSUMED TO HAVE 0.015% FUEL BOUND NITROGEN, OR LESS.
FUEL BOUND NITROGEN AMOUNTS GREATER THAN 0.015% WILL ADD TO THE REPORTED NOx VALUE.
* DATA NOT AVAILABLE
COMPRESSOR BLEED HEAT IS USED FOR PART LOAD OPERATION.
IPS–8707
JPT 4/14/92

1.1 ESTIMATED PERFORMANCE – PG7221(FA)

LOAD CONDITION		BASE	70%
AMBIENT TEMP.	– Deg F.	97	97
OUTPUT	– kW	142500.	98500.
HEAT RATE (LHV)	– Btu/kWh	10650.	12280.
HEAT CONS. (LHV) X10–6	– Btu/h	1517.6	1209.6
EXHAUST FLOW X10–3	– lb/h	3189.0	2510.0
EXHAUST TEMP	– Deg F.	1127.	1200.
EXHAUST HEAT X10–6	– Btu/h	881.7	758.7
WATER FLOW	– lb/h	92890.	68760.
NOX	– ppmvd @ 15% O2	42.	42.
NOX AS NO2	– lb/h	268.	211.
CO	– ppmvd	30.	*
CO	– lb/h	83.	*
UHC	– ppmvw	7.	*
UHC	– lb/h	13.	*
VOC	– ppmvw	3.5	*
VOC	– lb/h	6.5	*
PART	– lb/h	17.0	17.0

EXHAUST ANALYSIS % VOL.		
ARGON	0.85	0.85
NITROGEN	70.31	70.49
OXYGEN	11.03	11.07
CARBON DIOXIDE	5.11	5.11
WATER	12.71	12.48

SITE CONDITIONS		
ELEVATION	– ft.	160
SITE PRESSURE	– psia	14.62
INLET LOSS	– in. Water	4
EXHAUST LOSS	– in. Water	12
RELATIVE HUMIDITY	– %	48
FUEL TYPE	–	DISTILLATE
FUEL LHV	– Btu/lb	18550
APPLICATION	–	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	–	DRY LOW NOX II

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
DISTILLATE FUEL IS ASSUMED TO HAVE 0.015% FUEL BOUND NITROGEN, OR LESS.
FUEL BOUND NITROGEN AMOUNTS GREATER THAN 0.015% WILL ADD TO THE REPORTED NOx VALUE.
* DATA NOT AVAILABLE
COMPRESSOR BLEED HEAT IS USED FOR PART LOAD OPERATION.
IPS–8707
JPT 4/14/92

DRY LOW NOx COMBUSTOR
EXPECTED 501F COMBUSTION TURBINE PERFORMANCE AND EMISSIONS

Rev. 2
8/19/92

SITE CONDITIONS:

FUEL TYPE	GAS	GAS	GAS	GAS	GAS
LOAD LEVEL	BASE	BASE	BASE	BASE	BASE
FUEL HEATING VALUE, BTU/LB LHV	20900	20900	20900	20900	20900
FUEL HEATING VALUE, BTU/LB HHV	23200	23200	23200	23200	23200
AMBIENT TEMPERATURE, F	27	64	72	79	97
RELATIVE HUMIDITY	40	78	75	75	48
BAROMETRIC PRESSURE, PSIA	14.615	14.615	14.615	14.615	14.615
INLET PRESSURE LOSS, IN-WATER	4.0	3.7	3.6	3.5	3.4
EXHAUST PRESSURE LOSS, IN-WATER	11.0	9.6	9.3	9.0	8.4
INJECTION FLUID	NONE	NONE	NONE	NONE	NONE
INJECTION RATIO, LB/LB	0	0	0	0	0
GENERATOR POWER FACTOR	0.85	0.85	0.85	0.85	0.85
GENERATOR HYDROGEN PRESSURE, PSIA	30	30	30	30	30
GENERATOR FRAME (97 X 114)					

COMBUSTION TURBINE PERFORMANCE:

NET POWER OUTPUT, KW	169210	147950	143450	139560	128370
HEAT RATE, BTU/KWH LHV	9490	9900	10000	10100	10360
HEAT RATE, BTU/KWH HHV	10530	10990	11100	11210	11500
EXHAUST FLOW, LB/HR	3702540	3431310	3369010	3311770	3180510
EXHAUST TEMPERATURE, F	1063	1086	1092	1098	1111
FUEL FLOW, LB/HR	76830	70080	68640	67440	64130
INJECTION RATE, LB/HR	0	0	0	0	0
AUXILIARY LOAD, KW	400	400	400	400	400
HEAT INPUT, MMBTU/HR (LHV)	1606	1465	1435	1409	1340
HEAT INPUT, MMBTU/HR (HHV)	1782	1626	1592	1565	1488
EXHAUST ENERGY, MMBTU/HR	1053.5	1004.6	994.1	985.4	959.0

EXHAUST GAS COMPOSITION (BY PCT VOL):

OXYGEN	13.06	12.97	12.91	12.82	12.64
CARBON DIOXIDE	3.61	3.53	3.52	3.51	3.47
WATER	7.26	8.45	8.82	9.32	9.56
NITROGEN	75.09	74.11	73.81	73.41	73.20
ARGON	0.94	0.93	0.93	0.92	0.92
MOLECULAR WEIGHT	28.50	28.36	28.32	28.26	28.23

EMISSIONS

NOx, PPMVD @ 15% O2	25	25	25	25	25
NOx, LB/HR	163	148	145	143	136
CO, PPMVD	10	10	10	10	10
CO, LB/HR	35	32	31	31	29
SO2, PPMVD	1	1	1	1	1
SO2, LB/HR	2	1	1	1	1
TOTAL UHC, PPMVD	8	8	8	8	8
TOTAL UHC, LB/HR	16	15	14	14	13
VOC, PPMVD	4	4	4	4	4
VOC, LB/HR	8	7	7	7	7
PARTICULATES (PM10/TSP), LB/HR (TOTAL)	6.6	6.1	6.0	5.9	5.7
SOOT, LB/HR	6.3	5.9	5.8	5.7	5.5
ASH, LB/HR	0.0	0.0	0.0	0.0	0.0
H2SO4 MIST, LB/HR	0.2	0.2	0.2	0.2	0.2
CO2, PPMVD	40055	39729	39758	39894	39524
CO2, LB/HR	212418	193677	189813	186588	177228
OPACITY, %	<=10	<=10	<=10	<=10	<=10

NOTES:

1. The net power output is the power at the generator terminals minus turbine auxiliary loads.
2. The fuel composition for natural gas is per customer's specification.
3. Exhaust energy is referenced to 400 degrees Rankine.

DESTEC ENGINEERING – TIGER BAY PROJECT

DRY LOW NOx COMBUSTOR — Rev. 2

EXPECTED 501F COMBUSTION TURBINE PERFORMANCE AND EMISSIONS — 8/19/92

SITE CONDITIONS:

FUEL TYPE	GAS	GAS	GAS	GAS	GAS
LOAD LEVEL	70%	70%	70%	70%	70%
FUEL HEATING VALUE, BTU/LB LHV	20900	20900	20900	20900	20900
FUEL HEATING VALUE, BTU/LB HHV	23200	23200	23200	23200	23200
AMBIENT TEMPERATURE, F	27	64	72	79	97
RELATIVE HUMIDITY	40	78	75	75	48
BAROMETRIC PRESSURE, PSIA	14.615	14.615	14.615	14.615	14.615
INLET PRESSURE LOSS, IN–WATER	2.3	2.3	2.3	2.3	2.2
EXHAUST PRESSURE LOSS, IN–WATER	6.7	6.1	5.9	5.8	5.5
INJECTION FLUID	NONE	NONE	NONE	NONE	NONE
INJECTION RATIO, LB/LB	0	0	0	0	0
GENERATOR POWER FACTOR	0.85	0.85	0.85	0.85	0.85
GENERATOR HYDROGEN PRESSURE, PSIA	30	30	30	30	30
GENERATOR FRAME (97 X 114)					

COMBUSTION TURBINE PERFORMANCE:

NET POWER OUTPUT, KW	118330	103390	100210	97490	90340
HEAT RATE, BTU/KWH LHV	10490	11020	11150	11270	11600
HEAT RATE, BTU/KWH HHV	11650	12230	12370	12510	12880
EXHAUST FLOW, LB/HR	2754000	2678720	2647790	2619850	2554960
EXHAUST TEMPERATURE, F	1130	1130	1130	1130	1130
FUEL FLOW, LB/HR	59390	54520	53460	52570	50140
INJECTION RATE, LB/HR	0	0	0	0	0
AUXILIARY LOAD, KW	400	400	400	400	400
HEAT INPUT, MMBTU/HR (LHV)	1241	1139	1117	1099	1048
HEAT INPUT, MMBTU/HR (HHV)	1378	1265	1240	1220	1163
EXHAUST ENERGY, MMBTU/HR	834.4	816.3	808.4	801.9	782.8

EXHAUST GAS COMPOSITION (BY PCT VOL):

OXYGEN	13.04	13.10	13.09	13.04	13.15
CARBON DIOXIDE	3.62	3.47	3.44	3.41	3.33
WATER	7.30	8.32	8.68	9.12	9.29
NITROGEN	75.06	74.16	73.87	73.50	73.30
ARGON	0.94	0.93	0.93	0.92	0.92
MOLECULAR WEIGHT	28.49	28.37	28.33	28.28	28.25

EMISSIONS

NOx, PPMVD @ 15% O2	25	25	25	25	25
NOx, LB/HR	121	113	111	109	104
CO, PPMVD	10	10	10	10	10
CO, LB/HR	26	25	25	24	24
SO2, PPMVD	1	1	1	1	1
SO2, LB/HR	1	1	1	1	1
TOTAL UHC, PPMVD	8	8	8	8	8
TOTAL UHC, LB/HR	12	11	11	11	11
VOC, PPMVD	4	4	4	4	4
VOC, LB/HR	6	6	6	6	5
PARTICULATES (PM10/TSP), LB/HR (TOTAL)	4.9	4.8	4.7	4.7	4.6
SOOT, LB/HR	4.7	4.6	4.6	4.5	4.4
ASH, LB/HR	0.0	0.0	0.0	0.0	0.0
H2SO4 MIST, LB/HR	0.2	0.2	0.2	0.2	0.2
CO2, PPMVD	40247	39014	38766	38626	37815
CO2, LB/HR	158710	148643	145662	143146	136547
OPACITY, %	<=10	<=10	<=10	<=10	<=10

NOTES:

1. The net power output is the power at the generator terminals minus turbine auxiliary loads.
2. The fuel composition for natural gas is per customer's specication.
3. Exhaust energy is referenced to 400 degrees Rankine.
4. Part loads are achieved by modulating igvs.

DESTEC ENGINEERING – TIGER BAY PROJECT
DRY LOW NOx COMBUSTOR
EXPECTED 501F COMBUSTION TURBINE PERFORMANCE AND EMISSIONS

CTT–523D
Rev. 2
8/19/92

SITE CONDITIONS:

FUEL TYPE	OIL	OIL	OIL
LOAD LEVEL	PART	BASE	BASE
FUEL HEATING VALUE, BTU/LB LHV	18450	18450	18450
FUEL HEATING VALUE, BTU/LB HHV	19680	19680	19680
AMBIENT TEMPERATURE, F	27	72	97
RELATIVE HUMIDITY	40	75	48
BAROMETRIC PRESSURE, PSIA	14.615	14.615	14.615
INLET PRESSURE LOSS, IN–WATER	3.5	3.8	3.6
EXHAUST PRESSURE LOSS, IN–WATER	10.3	10.0	9.0
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, LB/LB	1.5	1.5	1.5
GENERATOR POWER FACTOR	0.85	0.85	0.85
GENERATOR HYDROGEN PRESSURE, PSIA	30	30	30
GENERATOR FRAME (97 X 114)			

COMBUSTION TURBINE PERFORMANCE:

NET POWER OUTPUT, KW	171970	162330	147180
HEAT RATE, BTU/KWH LHV	9280	9560	9850
HEAT RATE, BTU/KWH HHV	9900	10190	10510
EXHAUST FLOW, LB/HR	3502180	3509380	3311800
EXHAUST TEMPERATURE, F	1104	1104	1121
FUEL FLOW, LB/HR	86500	84110	78580
INJECTION RATE, LB/HR	129750	126170	117870
AUXILIARY LOAD, KW	600	600	600
HEAT INPUT, MMBTU/HR (LHV)	1596	1552	1450
HEAT INPUT, MMBTU/HR (HHV)	1702	1655	1546
EXHAUST ENERGY, MMBTU/HR	1054.5	1064.2	1024.3

EXHAUST GAS COMPOSITION (BY PCT VOL):

OXYGEN	11.92	11.88	11.83
CARBON DIOXIDE	5.00	4.83	4.76
WATER	10.60	11.91	12.57
NITROGEN	71.56	70.47	69.94
ARGON	0.90	0.89	0.88
MOLECULAR WEIGHT	28.33	28.17	28.09

EMISSIONS

NOx, PPMVD @ 15% O2	42	42	42
NOx, LB/HR	279	271	253
CO, PPMVD	50	50	50
CO, LB/HR	159	158	149
SO2, PPMVD	13	12	12
SO2, LB/HR	89	87	81
TOTAL UHC, PPMVD	20	20	20
TOTAL UHC, LB/HR	36	36	34
VOC, PPMVD	10	10	10
VOC, LB/HR	18	18	17
PARTICULATES (PM10/TSP), LB/HR (TOTAL)	39.6	39.0	36.7
SOOT, LB/HR	16.6	16.7	15.8
ASH, LB/HR	8.9	8.7	8.1
H2SO4 MIST, LB/HR	14.1	13.7	12.8
CO2, PPMVD	57653	56431	56099
CO2, LB/HR	280388	272545	254472
OPACITY, %	<=20	<=20	<=20

NOTES:

1. The net power output is the power at the generator terminals minus turbine auxiliary loads.
2. The fuel composition for distillate oil is per customer's specification.
3. Exhaust energy is referenced to 400 degrees Rankine.
4. Part loads are achived by modulating igvs.
5. Power output at 27 deg. F is limited to 172 MW.

DESTEC ENGINEERING – TIGER BAY PROJECT CTI-523D
DRY LOW NOx COMBUSTOR Rev. 2
EXPECTED 501F COMBUSTION TURBINE PERFORMANCE AND EMISSIONS 8/19/92

SITE CONDITIONS:

FUEL TYPE	OIL	OIL	OIL
LOAD LEVEL	70%	70%	70%
FUEL HEATING VALUE, BTU/LB LHV	18450	18450	18450
FUEL HEATING VALUE, BTU/LB HHV	19680	19680	19680
AMBIENT TEMPERATURE, F	27	72	97
RELATIVE HUMIDITY	40	75	48
BAROMETRIC PRESSURE, PSIA	14.615	14.615	14.615
INLET PRESSURE LOSS, IN-WATER	2.3	2.3	2.2
EXHAUST PRESSURE LOSS, IN-WATER	7.2	6.4	5.9
INJECTION FLUID	STEAM	STEAM	STEAM
INJECTION RATIO, LB/LB	1.5	1.5	1.5
GENERATOR POWER FACTOR	0.85	0.85	0.85
GENERATOR HYDROGEN PRESSURE, PSIA	30	30	30
GENERATOR FRAME (97 X 114)			

COMBUSTION TURBINE PERFORMANCE:

NET POWER OUTPUT, KW	133020	113400	102810
HEAT RATE, BTU/KWH LHV	9770	10310	10680
HEAT RATE, BTU/KWH HHV	10420	10990	11390
EXHAUST FLOW, LB/HR	2934960	2757580	2662180
EXHAUST TEMPERATURE, F	1130	1130	1130
FUEL FLOW, LB/HR	70440	63370	59510
INJECTION RATE, LB/HR	105660	95060	89270
AUXILIARY LOAD, KW	600	600	600
HEAT INPUT, MMBTU/HR (LHV)	1300	1169	1098
HEAT INPUT, MMBTU/HR (HHV)	1386	1247	1171
EXHAUST ENERGY, MMBTU/HR	904.4	855.3	828.0

EXHAUST GAS COMPOSITION (BY PCT VOL):

OXYGEN	12.08	12.17	12.26
CARBON DIOXIDE	4.91	4.67	4.53
WATER	10.43	11.58	12.09
NITROGEN	71.66	70.68	70.23
ARGON	0.90	0.88	0.88
MOLECULAR WEIGHT	28.34	28.19	28.12

EMISSIONS

NOx, PPMVD @ 15% O2	42	42	42
NOx, LB/HR	229	205	193
CO, PPMVD	50	50	50
CO, LB/HR	134	125	120
SO2, PPMVD	12	12	12
SO2, LB/HR	73	65	61
TOTAL UHC, PPMVD	20	20	20
TOTAL UHC, LB/HR	31	29	27
VOC, PPMVD	10	10	10
VOC, LB/HR	15	14	14
PARTICULATES (PM10/TSP), LB/HR (TOTAL)	32.6	30.0	28.5
SOOT, LB/HR	13.9	13.1	12.7
ASH, LB/HR	7.3	6.5	6.1
H2SO4 MIST, LB/HR	11.4	10.3	9.7
CO2, PPMVD	56460	54374	53041
CO2, LB/HR	230464	206946	194263
OPACITY, %	<=20	<=20	<=20

NOTES:

1. The net power output is the power at the generator terminals minus turbine auxiliary loads.
2. The fuel composition for distillate oil is per customer's specification.
3. Exhaust energy is referenced to 400 degrees Rankine.
4. Part loads are achieved by modulating igvs.

ATTACHMENT 2

FLORIDA GAS TRANSMISSION
NATURAL GAS SAMPLE ANALYSES

BEST AVAILABLE COPY

ANALYSIS

DATE: 04/28/92		ANALYSIS TIME:	345	STREAM SEQUENCE:	12
TIME:	11:22	CYCLE TIME:	360	STREAM#:	2
ANALYZER#:	1	MODE:	RUN	CYCLE START TIME:	11:16

COMP NAME	COMP CODE	MOLE %	GAL/MCF**	B.T.U.*	SP. GR.
HEXANE +	151	0.022	0.0096	1.13	0.000
PROPANE	152	0.162	0.0446	4.08	0.002
I-BUTANE	153	7892.15-6	0.0026	0.26	0.000
N-BUTANE	154	7528.58-6	0.0024	0.25	0.000
IPENTANE	155	4220.48-6	0.0015	0.17	0.000
NPENTANE	156	4062.01-6	0.0015	0.16	0.000
NITROGEN	157	0.418	0.0000	0.00	0.004
METHANE	158	96.588	0.0000	977.78	0.5549 0.538
CO2	159	0.804	0.0000	0.00	0.012
ETHANE	160	1.982	0.5302	35.15	0.020
TOTALS		100.000	0.5923	1018.97	0.57

* @ 14.730 PSIA DRY & UNCORRECTED FOR COMPRESSIBILITY

** @ 14.730 & 60 DEG. F

COMPRESSIBILITY FACTOR (1/Z)	= 1.0021
DRY B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1021.1
SAT B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1003.3
REAL SPECIFIC GRAVITY	= 0.5764
UNNORMALIZED TOTAL	= 99.86

ACTIVE ALARMS

NONE

Comm

1041.8 / 0.5939

1041.9 0.5939

→ TOTAL SULFUR = 0.35 Gr/ccf H_2S 0.05 Gr/ccF

0.8

BEST AVAILABLE COPY

ANALYSIS

DATE:	05/05/92	ANALYSIS TIME:	345	STREAM SEQUENCE:	12
TIME:	11:25	CYCLE TIME:	360	STREAM#: [illegible] 2	
ANALYZER#: [illegible] 1		MODE:	RUN	CYCLE START TIME:	11:19

COMP NAME	COMP CODE	MOLE %	GAL/MCF**	B.T.U.*	SP. GR.
HEXANE +	151	0.024	0.0106	1.25	0.00
PROPANE	152	0.172	0.0474	4.34	0.00
I-BUTANE	153	9949.88-6	0.0033	0.32	0.00
N-BUTANE	154	7610.23-6	0.0024	0.25	0.00
IPENTANE	155	3393.25-6	0.0012	0.14	0.00
NPENTANE	156	2694.51-6	0.0010	0.11	0.00
NITROGEN	157	0.348	0.0000	0.00	0.00
METHANE	158	96.786	0.0000	979.77	0.53
CO2	159	0.726	0.0000	0.00	0.01
ETHANE	160	1.919	0.5134	34.04	0.01
TOTALS		100.000	0.5793	1020.22	0.57

* @ 14.730 PSIA DRY & UNCORRECTED FOR COMPRESSIBILITY

** @ 14.730 & 60 DEG. F

COMPRESSIBILITY FACTOR (1/Z)	= 1.0021
DRY B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1022.4
SAT B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1004.6
REAL SPECIFIC GRAVITY	= 0.5752
UNNORMALIZED TOTAL	= 99.80

ACTIVE ALARMS

NONE

FLORIDA GAS TRANSMISSION CO.

[illegible] comm

[illegible] 1041.8 / 0.5939

1041.9 [illegible] 0.5939

→ TOTAL SULFUR 0.30 GR/CCF H_2S 0.05 Gr/CCF

1.0 [illegible] Bill [illegible]

BEST AVAILABLE COPY

ANALYSIS

DATE: 05/12/92		ANALYSIS TIME:	345	STREAM SEQUENCE: 12	
TIME: 12:17		CYCLE TIME:	360	STREAM#: 2	
ANALYZER#: 1		MODE:	RUN	CYCLE START TIME: 12:11	

COMP NAME	COMP CODE	MOLE %	GAL/MCF**	B.T.U.*	SP. GR.*
HEXANE +	151	0.021	0.0090	1.06	0.0007
PROPANE	152	0.177	0.0487	4.46	0.0027
I-BUTANE	153	0.014	0.0045	0.45	0.0003
N-BUTANE	154	0.012	0.0039	0.41	0.0003
IPENTANE	155	5825.91-6	0.0021	0.23	0.0001
NPENTANE	156	3664.47-6	0.0013	0.15	0.0001
NITROGEN	157	0.398	0.0000	0.00	0.0038
METHANE	158	96.669	0.0000	978.59	0.5355
CO2	159	0.748	0.0000	0.00	0.0114
ETHANE	160	1.952	0.5221	34.62	0.0203
TOTALS		100.000	0.5916	1019.95	0.5750

* @ 14.730 PSIA DRY & UNCORRECTED FOR COMPRESSIBILITY

** @ 14.730 & 60 DEG. F

COMPRESSIBILITY FACTOR (1/Z)	= 1.0021
DRY B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1022.1
SAT B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1004.3
REAL SPECIFIC GRAVITY	= 0.5760
UNNORMALIZED TOTAL	= 99.62

ACTIVE ALARMS

NONE

Comm.
1041.8/0.5939
1041.9 0.5938
→ ~~Total Sulfur~~ 0.35 Gr/CCF H2S 0.05 Gr/CCF
1.1 Bill Stimson

BEST AVAILABLE COPY

ANALYSIS

DATE: 05/19/92		ANALYSIS TIME:	345	STREAM SEQUENCE: 12	
TIME: 13:02		CYCLE TIME:	360	STREAM#: 2	
ANALYZER#: 1		MODE:	RUN	CYCLE START TIME: 12:56	

COMP NAME	COMP CODE	MOLE %	GAL/MCF**	B.T.U.*	SP. GR.*
HEXANE +	151	0.024	0.0105	1.24	0.0008
PROPANE	152	0.189	0.0521	4.77	0.0029
I-BUTANE	153	0.015	0.0048	0.47	0.0003
N-BUTANE	154	0.012	0.0038	0.39	0.0002
IPENTANE	155	4932.21-6	0.0018	0.20	0.0001
NPENTANE	156	3461.10-6	0.0013	0.14	0.0001
NITROGEN	157	0.405	0.0000	0.00	0.0039
METHANE	158	96.505	0.0000	976.92	0.5345
CO2	159	0.725	0.0000	0.00	0.0110
ETHANE	160	2.117	0.5662	37.54	0.0220
TOTALS		100.000	0.6404	1021.68	0.5758

* @ 14.730 PSIA DRY & UNCORRECTED FOR COMPRESSIBILITY

** @ 14.730 & 60 DEG. F

COMPRESSIBILITY FACTOR (1/Z)	= 1.0021
DRY B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1023.8
SAT B.T.U. @ 14.730 PSIA & 60 DEG. F CORRECTED FOR (1/Z)	= 1006.0
REAL SPECIFIC GRAVITY	= 0.5768
UNNORMALIZED TOTAL	= 99.83

ACTIVE ALARMS

NONE

FLORIDA GAS TRANSMISSION CO.

BROCKER LAB- Comm.

STANDARD GAS 1041.8 / 0.5939

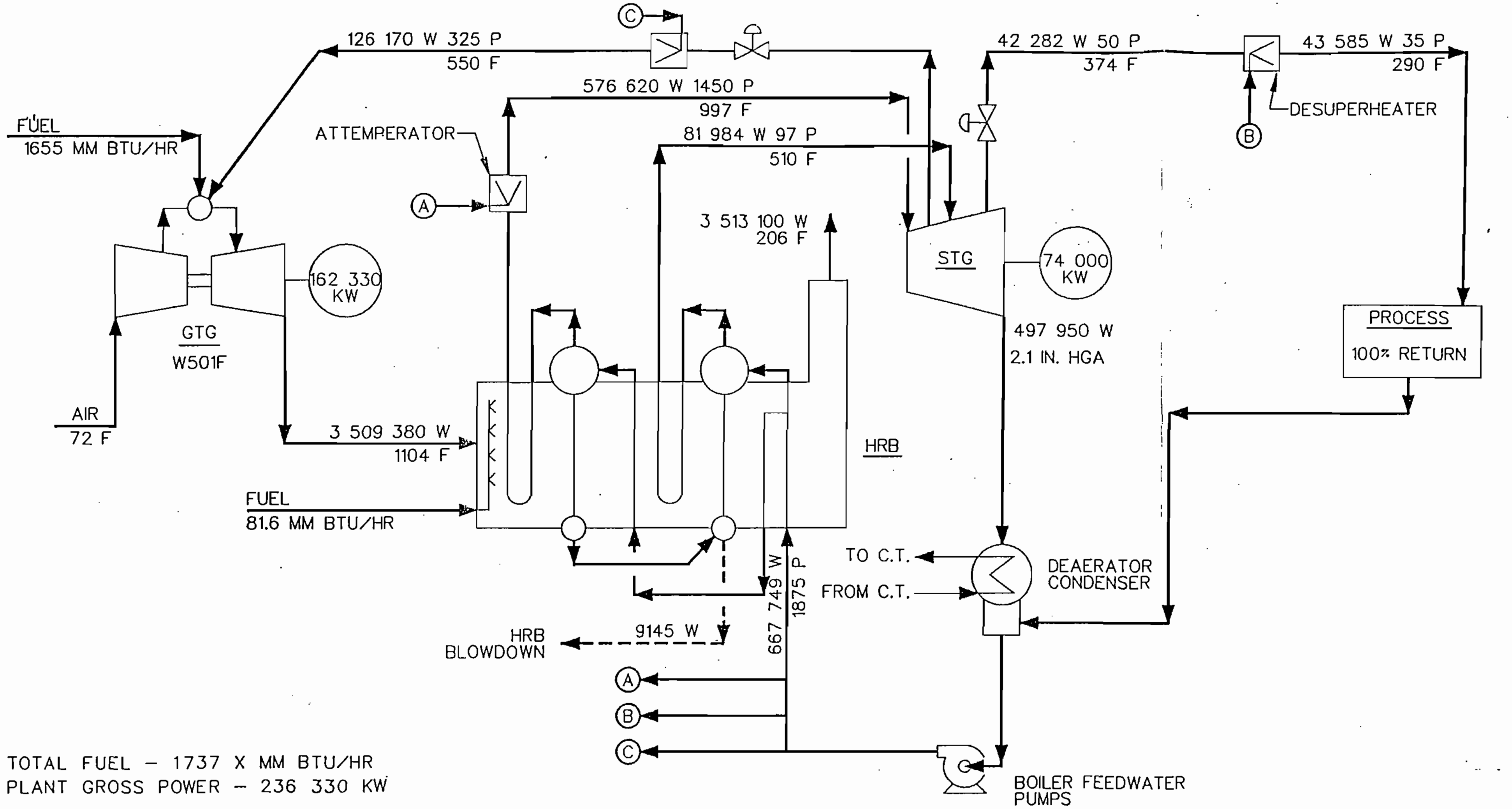
CERTIFIED VALUE BTU 1041.9 GRAV. 0.5939

TOTAL SULFUR 0.30 GR/CCF H^2S 0.05 GR/CCF

H^2O 1.1 #/MMCF BY Bill [signature]

ATTACHMENT 3

PROCESS FLOW DIAGRAMS
FOR THE COMBUSTION TURBINE
FIRING NATURAL GAS AND OIL



TOTAL FUEL – 1737 X MM BTU/HR
PLANT GROSS POWER – 236 330 KW

LEGEND
P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

SCALE : NONE	
CALC. TCE	DATE 8-25-92
DWN. RDP	DATE 8-25-92
CHK.	DATE
APPV.	DATE

DESTEC ENGINEERING

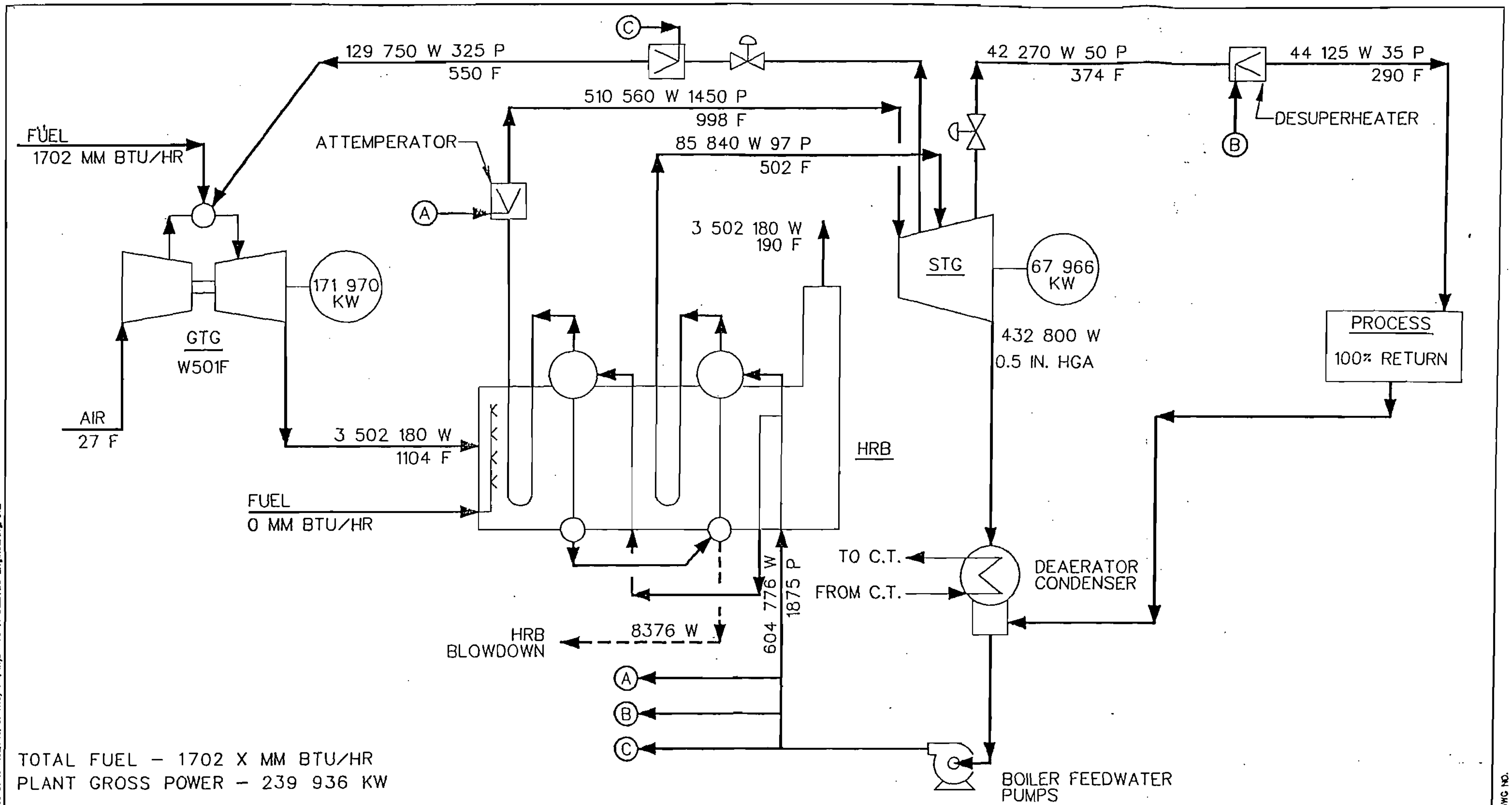
W501F
FLOW DIAGRAM
CASE: AVG AMB OIL FIRED

PROJECT NO.: 1253	
CLIENT: TIGER BAY COGEN	
DWG. NO.: 1253–M–017.01	REV. 0

DWG NO.

RDP

082592



LEGEND
P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

SCALE: NONE

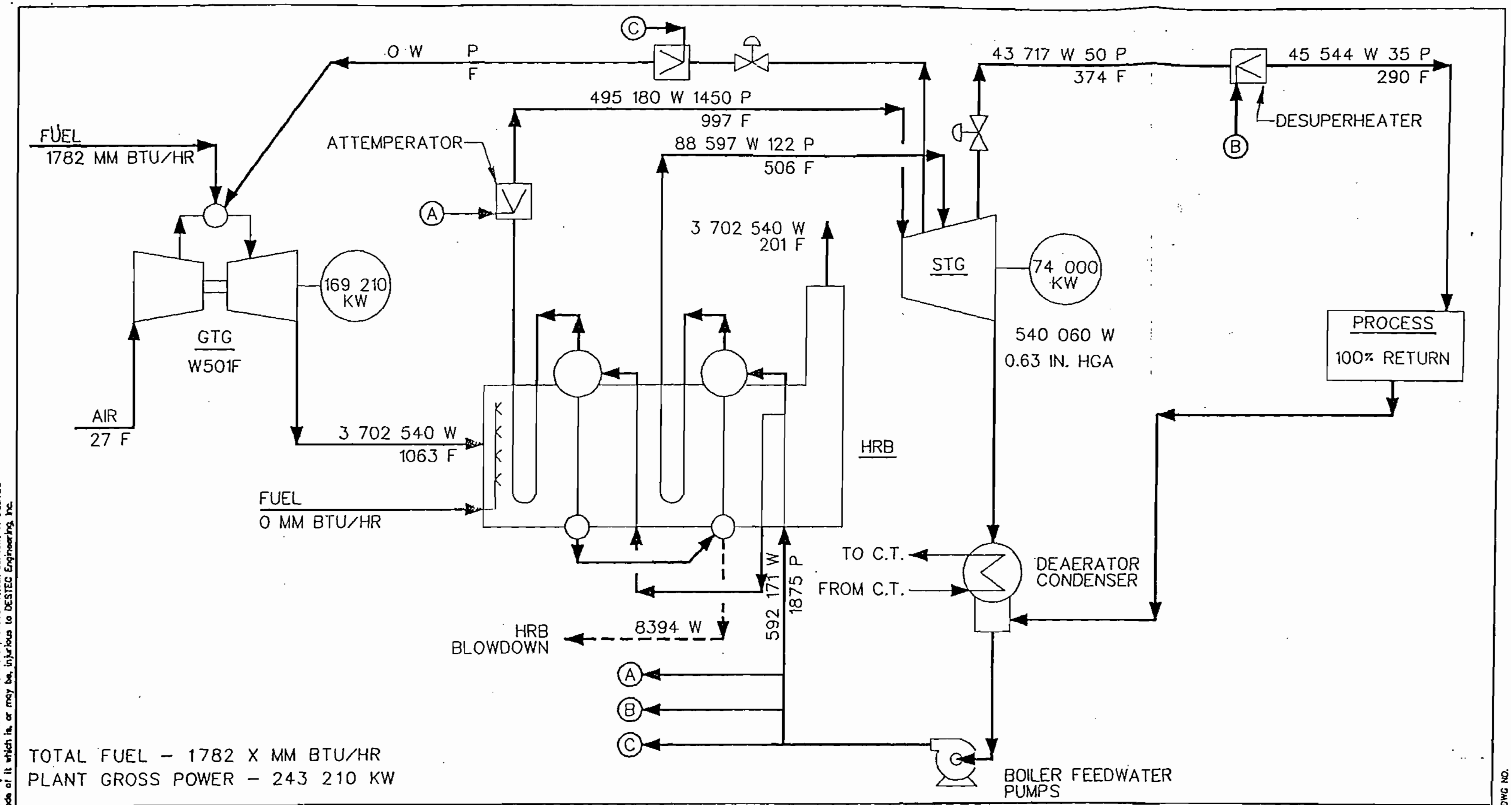
CALC. TCE	DATE 8-25-92
DWN. RDP	DATE 8-25-92
CHK.	DATE
APPV.	DATE

DESTEC ENGINEERING

W501F
FLOW DIAGRAM
CASE: WINTER DES OIL UNFIRED

PROJECT NO.: 1253
CLIENT: TIGER BAY COGEN
DWG. NO.: 1253-M-017.02
REV. 0

DWG NO. RDP 082592



LEGEND

P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

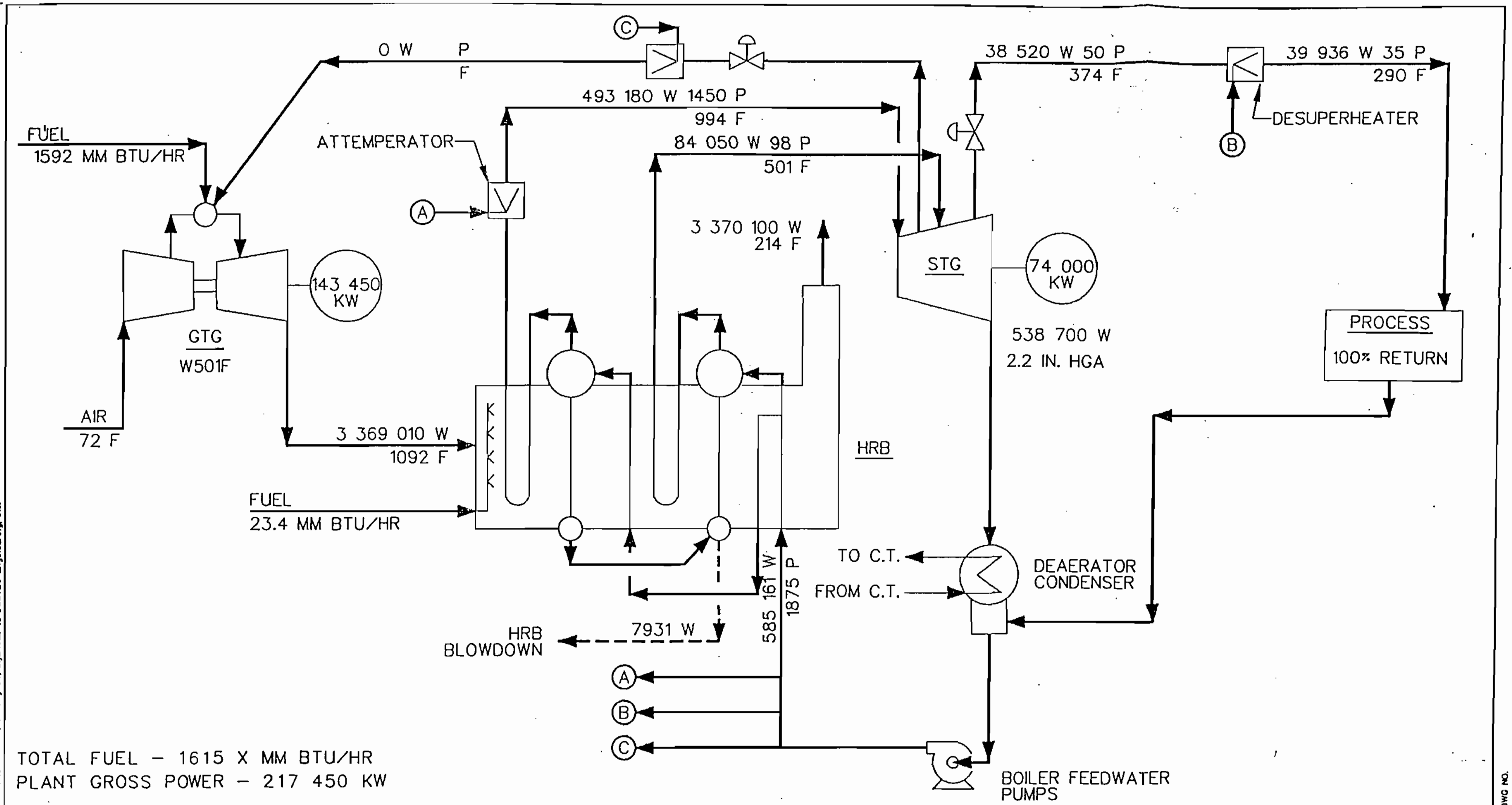
SCALE : NONE	
CALC. TCE	DATE 8-25-92
DWN. RDP	DATE 8-25-92
CHK.	DATE
APPV.	DATE

DESTEC
ENGINEERING

W501F
FLOW DIAGRAM
CASE: WINTER DES GAS UNFIRED

PROJECT NO.: 1253	
CLIENT: TIGER BAY COGEN	
DWG. NO.: 1253-M-017.03	REV. 0

DWG NO. RDP 052592



TOTAL FUEL – 1615 X MM BTU/HR
PLANT GROSS POWER – 217 450 KW

LEGEND
P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

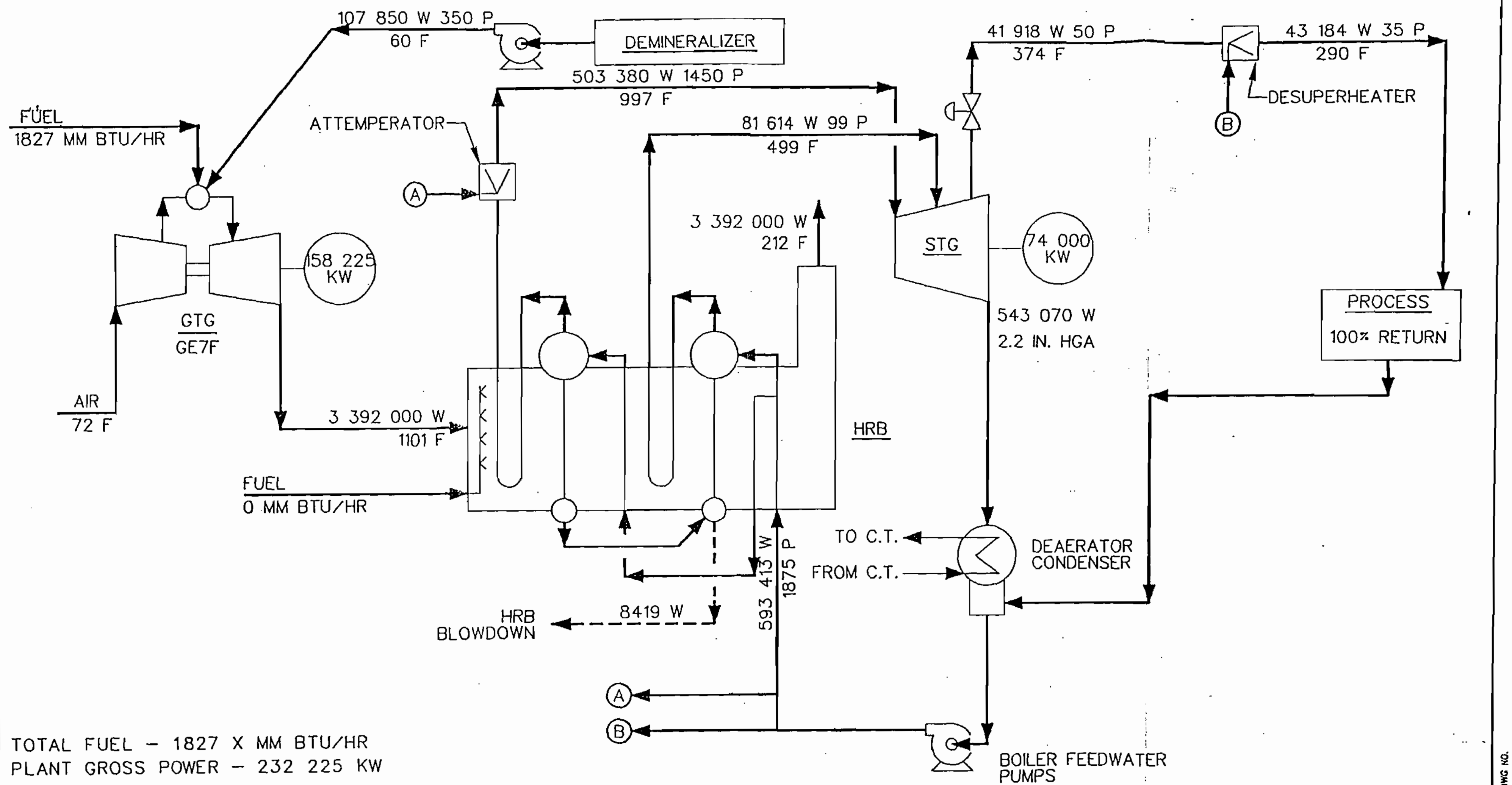
SCALE: NONE
CALC. TCE — DATE 8-25-92
DWN. RDP — DATE 8-25-92
CHK. — DATE
APPV. — DATE

DESTEC ENGINEERING

W501F
FLOW DIAGRAM
CASE: AVG AMB GAS UNFIRED

PROJECT NO.: 1253
CLIENT: TIGER BAY COGEN
DWG. NO.: 1253-M-017.04
REV. 0

DWG NO. RDP 082592



TOTAL FUEL – 1827 X MM BTU/HR
PLANT GROSS POWER – 232 225 KW

LEGEND

P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

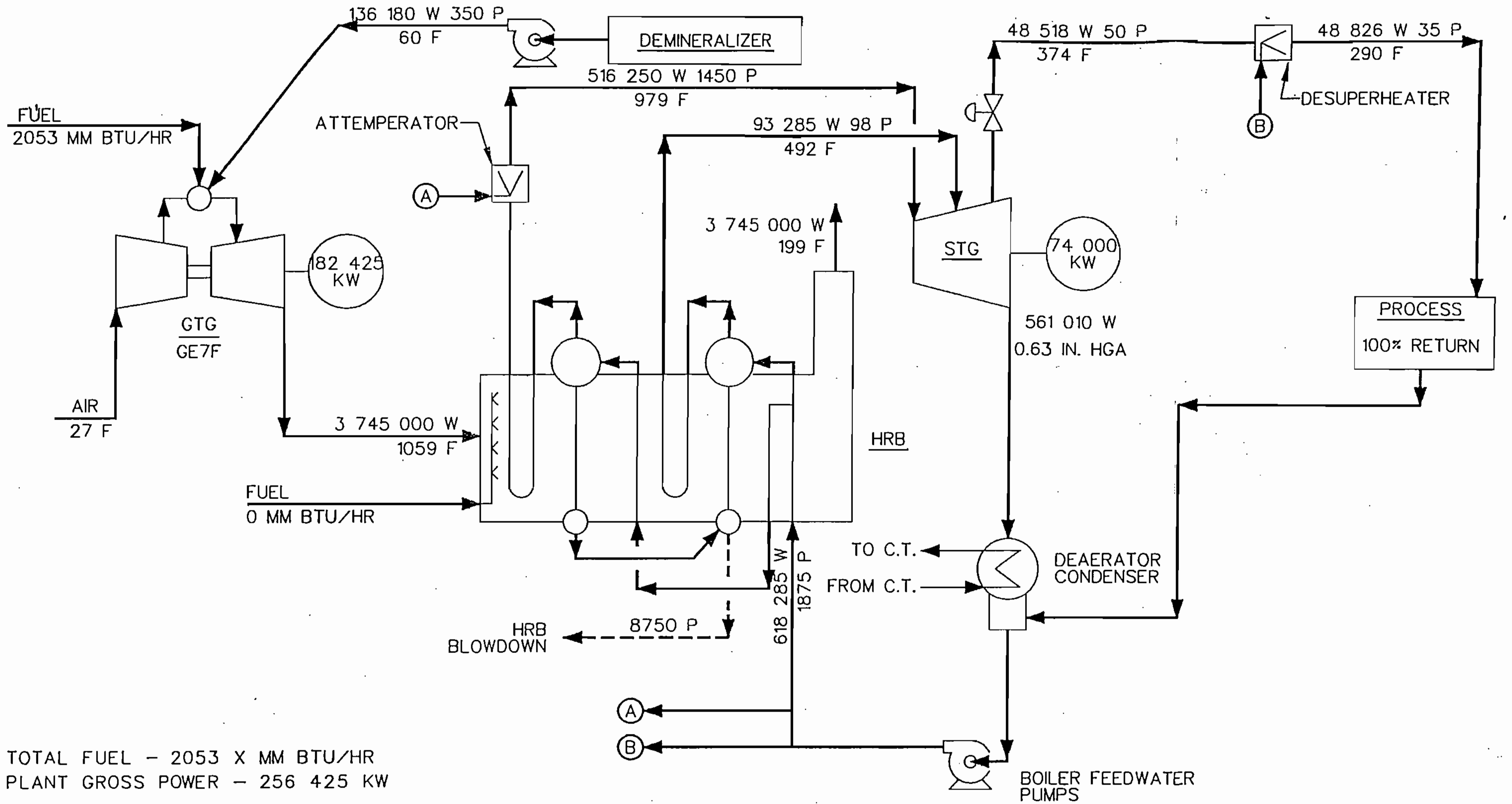
SCALE: NONE	
CALC. TCE	DATE 8-25-92
DWN. BHG	DATE 8-25-92
CHK.	DATE
APPV.	DATE

DESTEC ENGINEERING

GE PG72221 (FA)
FLOW DIAGRAM
CASE: AVG. AMB. OIL UNFIRED

PROJECT NO.: -1253	
CLIENT: TIGER BAY COGEN	
DWG. NO.: 1253-M-017.05	REV. 0

DWG NO. BHG 082592



TOTAL FUEL – 2053 X MM BTU/HR
PLANT GROSS POWER – 256 425 KW

LEGEND
P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

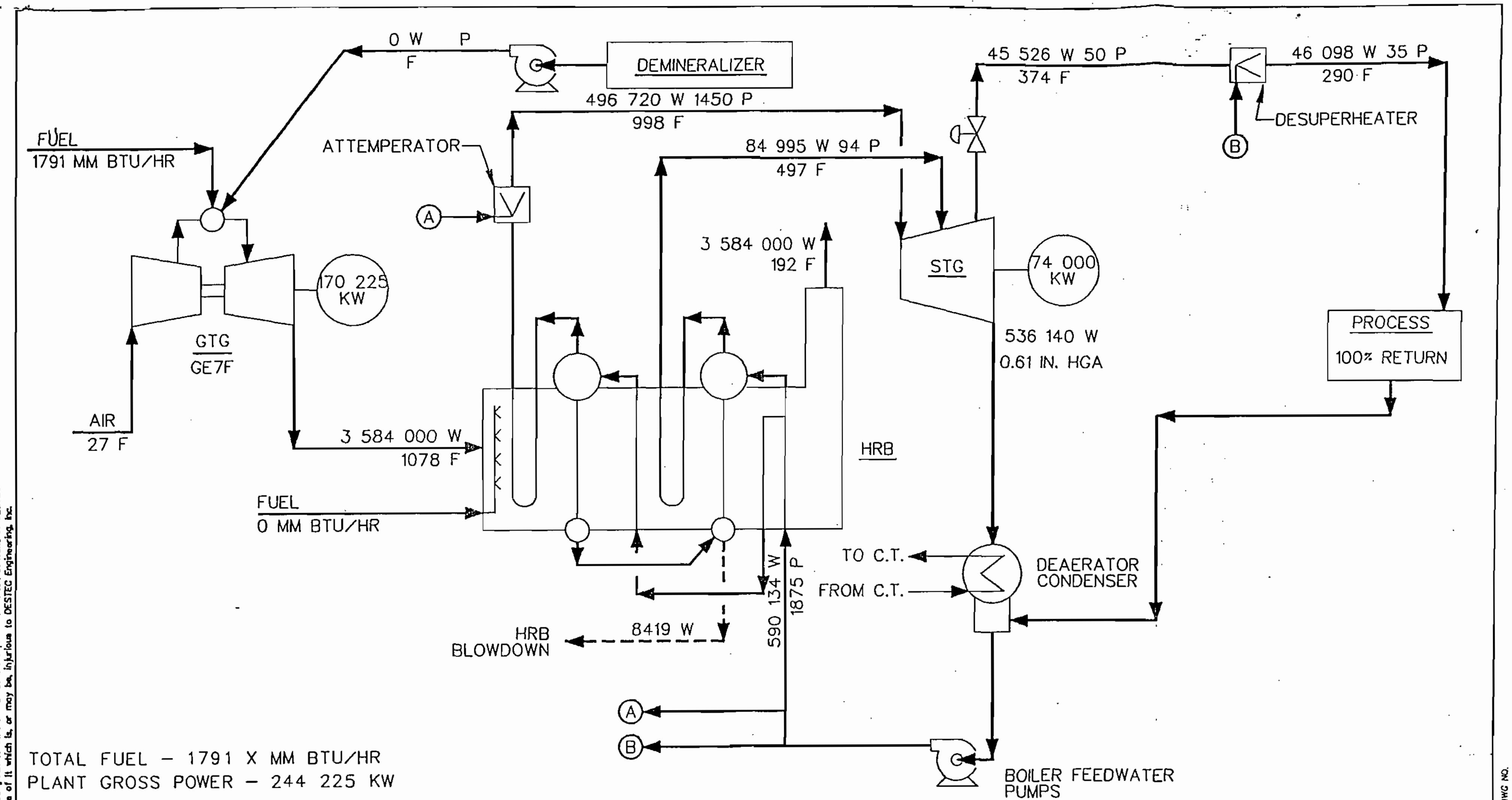
SCALE: NONE	
CALC. TCE	DATE 8-25-92
DWN. BHG	DATE 8-25-92
CHK.	DATE
APPV.	DATE

DESTEC ENGINEERING

GE PG7221 (FA)
FLOW DIAGRAM
CASE: WINTER DES. OIL UNFIRED

PROJECT NO.:	1253
CLIENT:	TIGER BAY COGEN
DWG. NO.: 1253-M-017.06	REV. 0

DWG NO. BHG 082592



LEGEND
P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS
W = LB/HR

NO.	DATE	REVISION	BY	APPV.

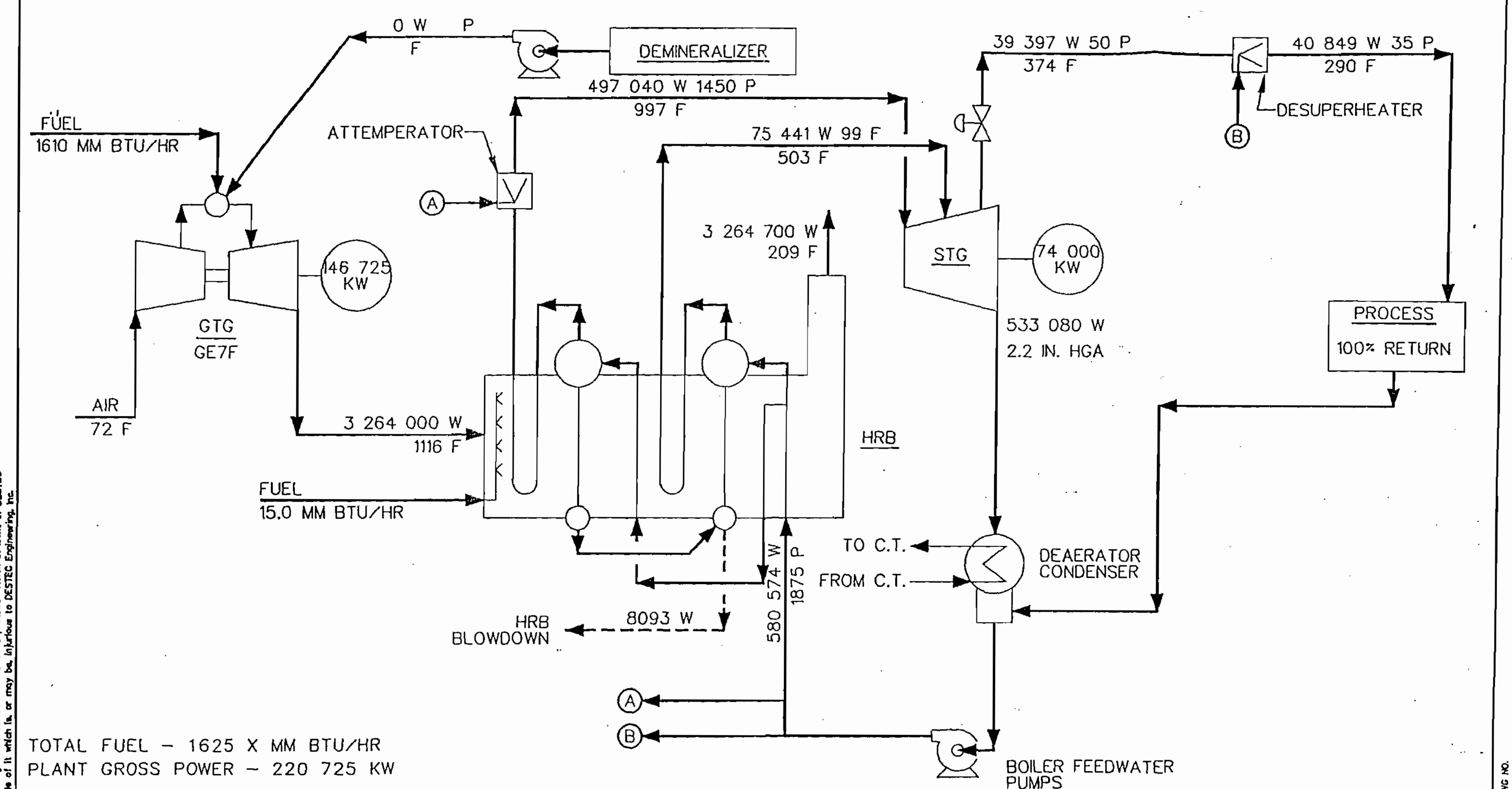
SCALE: NONE
CALC. TCE — DATE 8-25-92
DWN. BHG — DATE 8-25-92
CHK. — DATE
APPV. — DATE

DESTEC ENGINEERING

GE PG7221 (FA)
FLOW DIAGRAM
CASE: WINTER DES GAS UNFIRED

PROJECT NO.: 1253
CLIENT: TIGER BAY COGEN
DWG. NO.: 1253-M-017.07
REV. 0

BEST AVAILABLE COPY



LEGEND
P = PSIG
H = BTU/LB
F = °F
KW = KILOWATTS

NO.	DATE	REVISION	BY	APPV.

SCALE : NONE	
CALC. TCE	DATE 8-25-92
DWN. BHG	DATE 8-25-92
CHK.	DATE

DESTEC ENGINEERING

GE PG7221 (FA)
FLOW DIAGRAM

PROJECT NO.: 1253
CLIENT: TIGER BAY COGEN

DWG NO.
BHG

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

June 22, 1992

Mrs. Chris Shaver, Chief
Permit Review and Technical Support Branch
National Park Service-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Dear Mrs. Shaver:

RE: Central Florida Power Limited Partnership
206 MW Cogeneration Facility
Polk County, PSD-FL-190

The Department has received the above referenced PSD application. Please review this package for completeness and forward your comments to the Bureau of Air Regulation by July 10, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please call Mirza Baig 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 Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

June 22, 1992

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: Central Florida Power Limited Partnership
206 MW Cogeneration Facility
Polk County, PSD-FL-190

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 10, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Mirza Baig 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

DESTEC ENGINEERING

DESTEC ENGINEERING, INC.
2500 CITYWEST BLVD., SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

RECEIVED
JUN 25 1992
Division of Air
Resources Management

June 23, 1992

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

Re: Central Florida Power Limited Partnership

Dear Clair:

Please find enclosed a copy of the "Letter of Authorization" which was not included in our permit application and prevention of significant deterioration analysis for a 206-MW cogeneration facility. The application was submitted on June 12, 1992.

I will be contacting you in a week to review the initial comments your staff may have. In the meantime, please call if you have any questions.

Sincerely,

Robert S. Chatham

Robert S. Chatham, P.E.
Senior Environmental Engineer

RSC:tk

cc: Kennard F. Kosky, KBN
Barry Andrews, FDER
Mirza Baig, FDER
File

DESTEC ENGINEERING

DESTEC ENGINEERING, INC.
2500 CITYWEST BLVD., SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

June 12, 1992

TO WHOM IT MAY CONCERN:

Subject: Letter of Authorization

Please be advised that Robert I. Taylor, Project Manager, is authorized to represent Central Florida Power Limited Partnership in matters relating to necessary permits and approvals required from federal, state, county, and local regulatory authorities in the areas of air, water and land issues.

Sincerely,

Robert O. Rogers

Robert O. Rogers
President, Central Florida DGE Inc.
Managing General Partner of
Central Florida Power Limited Partnership

tk

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 next to the article number.

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. Robert I. Taylor
Project Manager
Central Florida Power, L.P.
2500 City West Blvd., Sutie 150
Houston, TX 77042

4a. Article Number
P 710 058 545

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

7. Date of Delivery
7-22-92

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 710 058 545

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

UNITED STATES POSTAL SERVICE

Sent to: Mr. Robert I. Taylor, Central FL Power, L.P.	
Street & No.: 2500 City West Blvd.	
P.O., State & ZIP Code: Houston, TX 77042	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 7-14-92 Permit: AC 53-214903 PSD-FL-190	

PS Form 3800, June 1990

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

July 14, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert I. Taylor, Project Manager
Central Florida Power, L.P.
2500 City West Blvd., Suite 150
Houston, Texas 77042

Dear Mr. Taylor:

On June 15, 1992, the Department received a PSD permit application to construct a 206 MW cogeneration power plant at the U.S. Agri-Chemicals Complex near Ft. Meade, Florida and deemed it incomplete. Please provide the following information:

1. Section 1-1 states the electrical output of the cogeneration facility is 206 MW. The gas turbine (GT) is rated at 147 MW and the duct burner is rated at 74 MW giving a total of 221 MW. What is the maximum electrical output you would like to be permitted for this facility?

2. According to Section 1-1, two types of advanced GTs are being considered for this project. The Department must know the exact type of gas turbine you propose to install so that a BACT determination can be made. Accordingly, please submit detailed information of the unit selected. We will also need any available stack test data for that unit.

3. What is the maximum sulfur content of the natural gas you propose to burn? Provide a copy of any sulfur content guarantee that you may have from the supplier.

4. Submit an updated process flow diagram showing steam turbine and volumetric air flow rates.

5. In Section 4-12, Table 4-2, the emissions (25 ppmvd) for advance GT with dry low-NO_x technology appears to be incorrect. Also Table 4-2 should state the turbine size on which these figures are based.

6. Submit all emission calculations and not just an example calculation. These emission calculations shall be based on the selected turbine for this project.

7. What is the expected maximum ambient concentrations for the metals emitted?

8. Please provide an air quality related analysis (AQRV) of the impact this project will have on the Chassahowitzka National Wilderness Area (CNWA) for the pollutant NO_2. The AQRV analysis includes impacts to soil, vegetation, and wild life. This analysis also includes an assessment of impacts to the aquatic environment. Since the modeling information already provided with this application shows that the predicted NO_2 impact at the CNWA Class I area is less than the National Park Service (NPS) recommended significance level, the NPS has verbally stated that only a literature review is needed in order to comply with the AQRV analysis requirement.

9. Section 4.3.1.2, page 4-10, states that "While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustion design." How much additional thermal NO_x generated is due to higher temperature?

10. On page 4-3, the estimated cost of SCR is reported to be about $7400 per ton of NO_x removed and it exceeds $10,000 per ton of pollutant removed when the net emissions of all pollutants (exclusive of CO_2) are considered. Provide us with the names and addresses of all manufacturers that were contacted while developing capital and annualized cost estimates for this project.

The processing of your application will continue upon receipt of the above requested information. If you have any questions, please contact Mr. Mirza P. Baig at (904) 488-1344.

Sincerely,

For [signature]

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

CHF/MB/plm

cc: Bill Thomas, SWD
Ken Kosky, P.E., KBN Eng.
Robert Chatham, Destec Eng.
Jewell Harper, EPA, Atlanta
Chris Shaver, NPS

CC MIRZA BAIG
LELEVR HOLADAY
Plan to attend
Tuesday 10 AM MTG
Preston 4/10/92

DESTEC ENGINEERING

DESTEC ENGINEERING, INC.
2500 CITYWEST BLVD., SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

April 9, 1992

APIS No 020 40TPA53023801

Mr. Preston Lewis
Bureau of Air Regulations
Florida Department of Environmental Regulations
2600 Blairstone Road
Tallahassee, FL - 32399-2400

Subject: **Central Florida Cogeneration Plant**
Fort Meade, Polk County
Preliminary Information and Pre-Application Meeting

Dear Mr. Lewis:

The Central Florida Power Limited Partnership is planning a 210 MWe (nominal) cogeneration project at the U.S. Agri Chemicals Complex near Ft. Meade, Florida. The project will be called the Central Florida Cogeneration Plant. Destec Energy, Inc. is one of the partners, and is the developer of the project. Destec Operating Company will operate and maintain the cogeneration plant under contract to the Partnership. All pollution-emitting activities, including emission controls, will be under Destec control. Destec Engineering, Inc., an affiliate of Destec Energy, is under contract to the limited partnership to perform engineering services for the project, including air permitting.

The project will consist of one gas turbine (GT) electric generating unit, equipped with a duct burner-fired heat recovery steam generator (HRSG). The GT/HRSG unit will be primarily fired with natural gas, distillate oil will be used as the emergency backup fuel for the GT.

This letter presents a brief overview of the project, our preliminary analysis of the air emissions due to the project, and our understanding of the air permitting requirements and air regulations which apply to the project. We have concluded that a FDER construction permit will be required, and that certain NSPS will apply. We have also concluded that a PSD permit will be required for carbon monoxide (CO), nitrogen oxides (NO_x), volatile organic compounds (VOC), particulate matter (PM), and particulate matter less that 10 microns (PM-10).

We understand that PSD review will not apply for sulfur dioxide (SO_2) and other PSD-regulated pollutants, because the project will not cause significant emissions for these pollutants. We further understand that Nonattainment New Source Review (NNSR) will not apply to the project's emissions, because the project is not located in a nonattainment area.

We look forward to meeting at the FDER on Tuesday, April 14, 1992 at 10:00 AM to discuss the project and confirm the project's permitting requirements, procedures, and timing. We are especially interested in obtaining FDER input regarding BACT considerations for NO_x, CO, VOC, PM, PM-10 and the timing of air dispersion modeling submittals. Destec Engineering, Inc. has engaged the services of KBN Engineering (KBN) to prepare the air permit applications. Representatives of Destec, General Peat Resources and KBN will be present at the meeting.

Project Schedule

Contingent upon receipt of the necessary pre-construction approvals, construction of the Cogeneration Plant is scheduled to be financed by December 1992, construction begin by June 1993, and be operational by January 1995.

Project Overview

Attachment 1 to this letter shows the general location of the project in Florida and Polk County. Polk County is classified as "attainment" or "cannot be classified" for all criteria pollutants.

Attachment 2 shows the specific project location in the U.S. Agri Chemicals Complex near Ft. Meade. The project will provide process steam to the U.S. Agri Chemicals complex. Electric power will be supplied to the public utility grid.

Destec personnel will operate and maintain the cogeneration plant under contract to the Partnership. The cogeneration plant manager will be a Destec employee. The plant will be owned by the limited partnership. An affiliate of Destec Energy, Inc., General Peat Resources and EcoEnergy will have ownership interest in the partnership.

The project is evaluating different manufacturers of gas-fired turbines. The gas turbine unit will have a nominal electrical output of about 150 MWe, a maximum heat input of about 1900 MMBtu/hr (HHV), and will be equipped with dry low NO_x combustors. The gas turbine's exhaust will be routed to a duct burner-fired HRSG unit, normally unfired. The natural gas-fired duct burner for the HRSG unit is expected to have a maximum heat input of about 125 MMBtu/hr (HHV). The steam from the HRSG unit will power a steam turbine electrical generator, with a maximum output of about 74 MWe.

Approximately 40,000 lb/hr of low pressure steam will be exported to the U.S. Agri Chemical complex for use as thermal energy.

Electrical power will be sold to the public utility grid.

Project Emissions

By firing natural gas the gas turbine exhaust (entering the HRSG) will be limited to 25 ppmvd NO_x, at 15% oxygen, and 15 ppmvd CO. Advanced dry low NO_x technology combustors and other measures will be used to control the NO_x emissions from the project's gas turbine and duct burner while firing natural gas. The duct burners will be only fired on natural gas. The duct burner NO_x emissions will be about 0.10 lb/MMBtu.

When firing distillate oil, the gas turbine exhaust entering the HRSG will be limited to 42 ppmvd NO_x at 15% oxygen and 30 ppmvd CO. Steam or water injection will be utilized for NO_x control when firing distillate oil. The annual distillate oil usage is anticipated to be approximately 350 hours per year.

The planned permit application will present calculations of maximum hourly and annual emission rates for all regulated pollutants for each emitting unit. For purposes of evaluating how PSD regulations may apply to the project, Destec has performed preliminary, worst-case emissions calculations of annual emissions. These calculations are summarized and discussed below.

Destec may present slightly different calculated emissions in the planned permit application, based on operational limitations that may be proposed to FDER as part of the requested permit.

In the preliminary, worst-case emissions calculations the single GT/HRSG is assumed to operate at maximum rated heat input, year-round. This calculational basis considerably over estimates the emissions that will actually occur, since (1) the gas turbine will at times be operated at less than maximum capacity and (2) the duct burner in the HRSG will not normally be operated. The following table summarizes the preliminary, worst-case emissions calculations and compares the calculated emissions to the PSD significance levels:

	Worst Case Project Emissions (T/yr)	**PSD Significance Level (T/yr)**
Carbon monoxide (CO)	324	100
Nitrogen oxides (NO_x)	750	40
Sulfur dioxide (SO_2)	39	40
Particulate matter (PM)[a] and PM-10	48	25/15
Volatile organic compounds (VOC)	58	40
Non-criteria PSD regulated pollutants	None or Negligible	Project emissions will be insignificant

[a] The permit application will conservatively assume that PM will consist 100% of PM-10.

Applicability of PSD and NNSR Review

Destec's understanding of the PSD regulations is that the planned Cogeneration Plant is not one of the 28 source types, therefore, the criterion of "major source" is 250 T/yr of any regulated pollutant. On that basis, and based on the preliminary emissions calculations summarized above, the cogeneration plant will be a major stationary source, since the plant will emit 250 T/yr or more CO and NO_x. Destec understands, therefore, that PSD is applicable to all PSD-regulated pollutants which the plant will emit in significant amounts. Destec further understands that, because the cogeneration plant will be a new "stationary source" under separate control from the U.S. Agri Chemical complex, netting of contemporaneous increases and decreases is not applicable. Therefore, Destec has concluded that PSD will apply to all pollutants for which significant emissions will occur from the new cogeneration plant. As shown on the table in the preceding section, the plant will be significant for CO, NO_x, VOC, PM and PM-10. Therefore, we understand that PSD review will apply to the project for CO, NO_x, VOC, PM and PM-10.

The plant will have insignificant emissions of SO_2, lead, and non-criteria PSD regulated pollutants. Therefore, we understand that the project will not be subject to PSD review for SO_2, lead, and non-criteria PSD-regulated pollutants. Also, we understand that the project will not be subject to NNSR review.

Applicability of NSPS Regulations

Based upon the preliminary project plans, we understand that the Cogeneration Plant will be subject to some of the New Source Performance Standards contained in:

- 40 CFR 60 Subpart GG: Stationary Gas Turbines
- 40 CFR 60 Subpart Db: Industrial - Commercial - Institutional Steam Generating Units

In addition, the project's duct burner-fired HRSG unit does not appear to not be subject to Subpart D or Da since the duct burners' maximum heat input capacity of 125 MMBtu/hr does not exceed the applicability level of 250 MMBtu/hr.

Regarding the NSPS for a gas turbine in 40 CFR 60 Subpart GG, the turbines will be subject to the Subpart GG limits for sulfur dioxide, which require that the exhaust gases do not exceed 150 ppmv SO_2 (at 15% O_2, dry basis) and that the fuel does not contain more than 0.8 percent sulfur by weight. The turbine and fuels will easily comply with these limits. We understand that the cogeneration plant will be required to periodically monitor and report fuel sulfur content in accordance with the Subpart GG NSPS.

Regarding the NSPS for steam generating units in 40 CFR 60 Subpart Db., the project's duct burner-fired HRSG unit will be subject to the NSPS, because the maximum fuel firing rate (about 125 MMBtu/hr/duct burner (HHV)) is greater that the NSPS applicability threshold of 29 MWe (100 MMBtu/hr). The Subpart Db NSPS requires that affected duct burners meet a NO_x emission limit of 0.2 lb/MMBtu heat input, which is applicable to firing natural gas in duct burners of combined cycle systems (see 40 CFR 60.44b(e)). The planned duct burners will have no difficulty in meeting the NSPS. The duct burners will be fired only on natural gas.

CO BACT Considerations

The gas turbines dry low NO_x combustors are guaranteed to limit CO to 15 ppmvd, natural gas, and limit CO to 30 ppmvd, firing distillate oil and injecting steam or water. At the CO emission rates which correspond to this low concentration, the ambient CO impacts of the project are expected to be negligible (i.e., well below FDER and EPA significance thresholds). Given the low CO emissions and negligible impacts, we currently anticipate proposing the low NO_x controls as BACT for CO. We would like to obtain FDER input prior to preparing our BACT analysis and permit applications.

Contents of Air Permit Applications

We plan to submit two separate permit application documents for the Cogeneration Plant:

- FDER construction permit application
- PSD application

Destec Engineering and KBN are now beginning to assemble the information and perform the analysis to be included in the permit applications.

The FDER permit application is expected to include the following information:

- Completed FDER permit application forms
- Certifications (i.e. professional engineers certification)
- Description of the project and the process, with an area map, plot plant and process flow diagram. Emphasis will be placed on sources of emissions and emission control measures.
- BACT analysis for CO, NO_x, SO_2, PM, PM-10 and VOC
- Description of applicable air regulatory requirements
- Appendicized emission rate calculations, along with the inputs and assumptions used.
- Dispersion modeling analysis in accordance with protocols agreed upon with FDER.

The PSD permit application will include much of the same information included in the state application, except that the PSD BACT analysis and any dispersion modeling analysis will address only CO, NO_x, PM, VOC, and PM-10. The PSD application's BACT analysis for NO_x and CO will be quite brief, because we understand that our planned BACT measures for NO_x and CO represent the "top" level of BACT, consistent with current FDER and EPA policies. The PSD application's BACT analysis for PM and PM-10 is also expected to be quite brief, because we are aware of no control techniques (aside from modern design and good combustion practices) for PM/PM-10 emissions from gas-fired/oil-fired gas turbines and gas-fired duct burners.

With respect to dispersion modeling, we currently anticipate submitting modeling analysis when the permit applications are submitted to FDER. We anticipate that a separate modeling protocol meeting with FDER modelers will be required to confirm specific procedures prior to performing the modeling.

We look forward to meeting with you on April 14th to confirm the air permitting requirements and timing for the project. In the interim, if there are any questions regarding the project or this letter, please call me at (713) 735-4087.

Sincerely,
DESTEC ENGINEERING, INC.

Robert S. Chatham

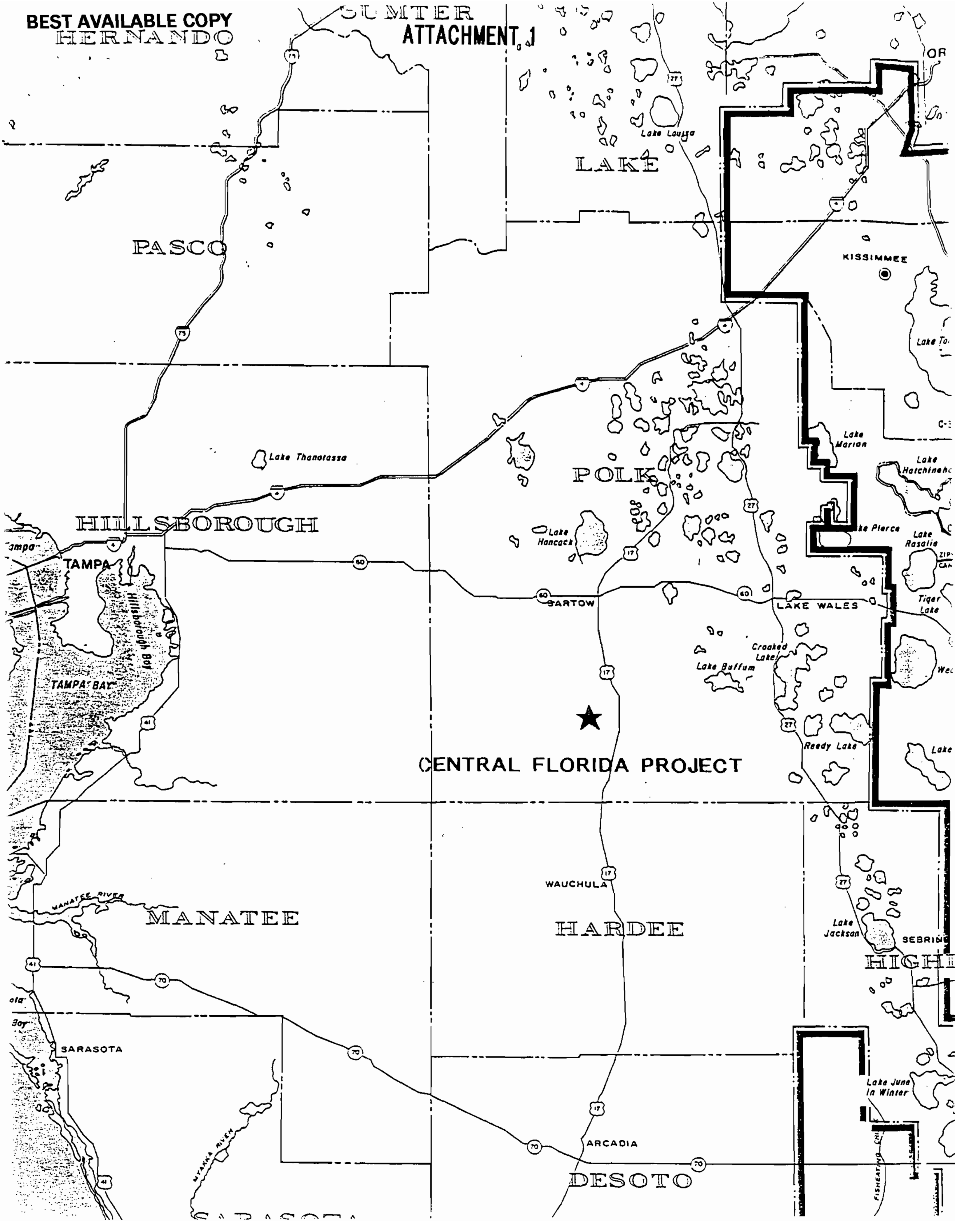
Robert S. Chatham
Environmental Engineer

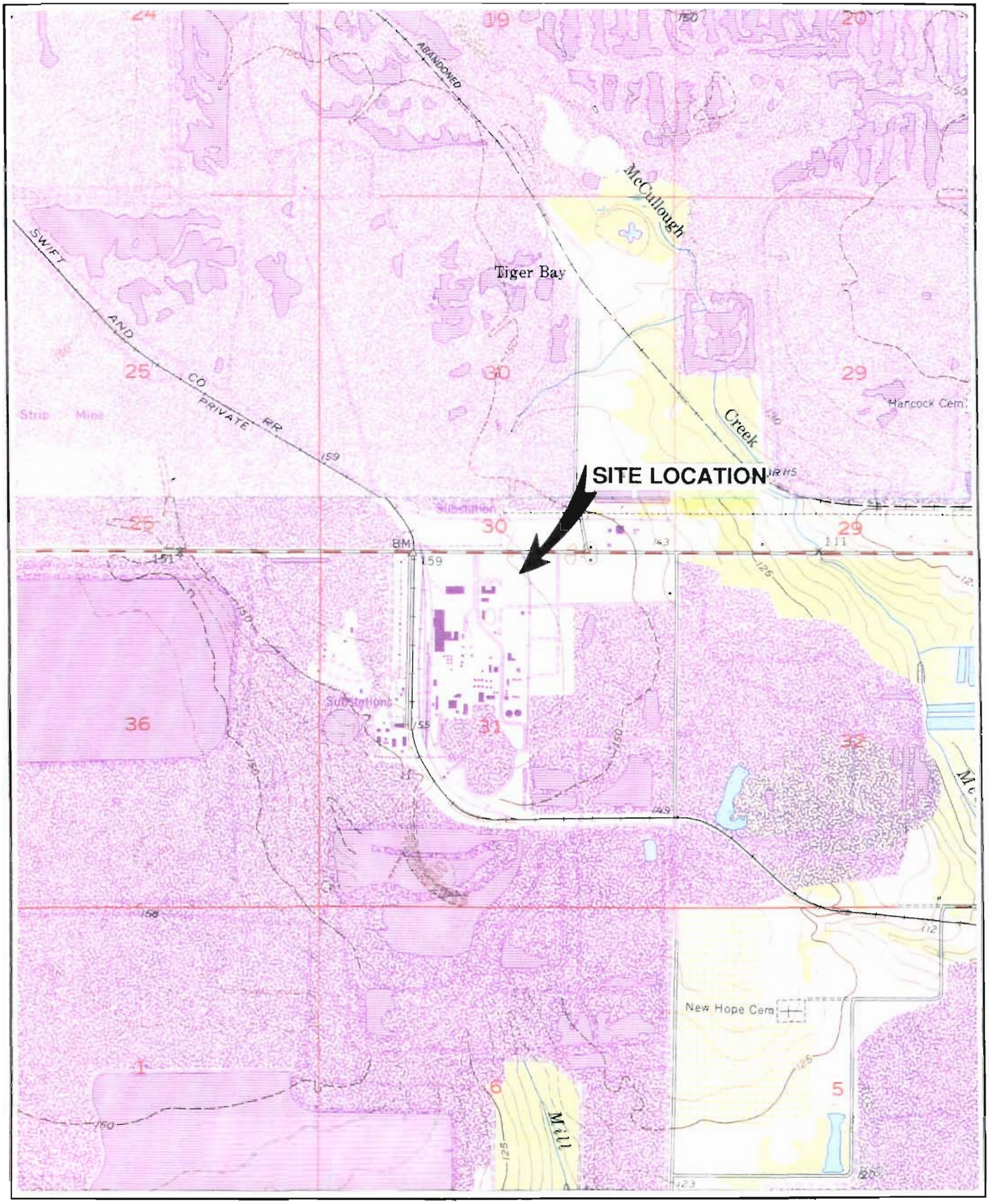
cc: Mr. J. W. Kenny, General Peat Resources
Mr. Ken Kosky, KBN

Attachments:
1 - Project Location in Florida and Polk County
2 - Project Location within U.S. Agri Chemicals Complex

BEST AVAILABLE COPY

ATTACHMENT 1





ATTACHMENT 2
PROJECT LOCATION MAP

SOURCES: USGS, 1987; KBN, 1992.

DESTEC ENGINEERING

WAIVER OF 90 DAY TIME LIMIT
UNDER SECTIONS 120.60(2) and 403.0876, FLORIDA STATUTES

License (Permit, Certification) Application No. AC 53-214903
PSD-FL-190

Applicant's Name: Central Florida Power, L.P.
Tiger Bay Cogeneration Plant

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 15th day of January 19 93.

The undersigned is authorized to make this waiver on behalf of the applicant.

RI Taylor
Signature

Robert I. Taylor, Project Manager
Name (Please Type or Print)

Revised April, 1990

DESTEC ENGINEERING

DESTEC ENGINEERING, INC.
2500 CITYWEST BLVD., SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

Date: December 30, 1992

To: Preston Lewis

From: Robert Chatham

	Document	Date/ Revision	Job No./ Project	Note
1.	Waiver of 90 Day Time Limit		1253	
2.				
3.				
4.				

Notes:

Cover

Package

cc: Teresa Heron (FDER)
Patti Adams (FDER)

File

1253

FEDERAL EXPRESS

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL
PACKAGE TRACKING NUMBER 1028818486

1196F 1028818486

RECIPIENT'S COPY

Date 6/13/92

1 From (Your Name) Please Print: Kennard F. Kosky	Your Phone Number (Very Important): (904) 331-9000	2 To (Recipient's Name) Please Print: ClairFancy	Recipient's Phone Number (Very Important): (904) 488-1344
Company: KBN ENG & APPLIED SCIENCES	Department/Floor No.	Company: Bureau of Air Regulation Florida Dept of Environmental Regulation	Department/Floor No.
Street Address: 1034 NW 57TH ST		Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.): Twin Towers Office Bldg 2600 Blairstone Rd	
City: GAINESVILLE State: FL	ZIP Required: 32605	City: Tallahassee State: FL	ZIP Required: 32399-2400

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.)
12018-0400 KFK/LCB

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address
City State ZIP Required

3 PAYMENT 1 [x] Bill Sender 2 [ ] Bill Recipient's FedEx Acct. No. 3 [ ] Bill 3rd Party FedEx Acct. No. 4 [ ] Bill Credit Card
5 [ ] Cash/Check

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)
- 11 [x] YOUR PACKAGING
- 16 [ ] FEDEX LETTER *
- 12 [ ] FEDEX PAK *
- 13 [ ] FEDEX BOX
- 14 [ ] FEDEX TUBE

Standard Overnight (Delivery by next business afternoon†)
- 51 [ ] YOUR PACKAGING
- 56 [ ] FEDEX LETTER *
- 52 [ ] FEDEX PAK *
- 53 [ ] FEDEX BOX
- 54 [ ] FEDEX TUBE

Economy Two-Day (Delivery by second business day†)
- 30 [ ] ECONOMY

Government Overnight (Restricted for authorized users only)
- 46 [ ] GOVT LETTER
- 41 [ ] GOVT PACKAGE

Freight Service (for Extra Large or any package over 150 lbs.)
- 70 [ ] OVERNIGHT FREIGHT **
- 80 [ ] TWO-DAY FREIGHT **

(Confirmed reservation required)
† Delivery commitment may be later in some areas
*Declared Value Limit $100.
**Call for delivery schedule

5 DELIVERY AND SPECIAL HANDLING (Check services required)
- 1 [ ] HOLD FOR PICK-UP (Fill in Box H)
- 2 [x] DELIVER WEEKDAY
- 3 [ ] DELIVER SATURDAY (Extra charge) (Not available to all locations)
- 4 [ ] DANGEROUS GOODS (Extra charge)
- 5 [ ]
- 6 [ ] DRY ICE ______ Lbs.
- 7 [ ] OTHER SPECIAL SERVICE
- 8 [ ]
- 9 [ ] SATURDAY PICK-UP (Extra charge)
- 10 [ ]
- 11 [ ] DESCRIPTION
- 12 [ ] HOLIDAY DELIVERY (If offered) (Extra charge)

6 PACKAGES | WEIGHT In Pounds Only
Total 1 | Total 24

DIM SHIPMENT (Chargeable Weight)
[ ] ______ lbs.
___ x ___ x ___ = ___

Received At
1 [ ] Regular Stop 3 [ ] Drop Box
2 [ ] On-Call Stop 4 [ ] B.S.C. 5 [ ] Station

Emp. No. Date
[ ] Cash Received
[ ] Return Shipment
[ ] Third Party [ ] Chg. To Del. [ ] Chg. To Hold
Street Address
City State Zip
Received By:
X
Date/Time Received FedEx Employee Number

7 Release Signature:
FedEx Emp. No. Date/Time

Federal Express Use	
Base Charges	
Declared Value Charge	
Other 1	
Other 2	
Total Charges	

REVISION DATE 4/91
PART #137204 FXEM 6/91
FORMAT #082

082

Destec Energy Inc.
P.O. Box 4411
Houston, Texas 77210

DATE 06/03/92

CHECK NUMBER 63199

PAYMENT ADVICE

INVOICE NUMBER	INVOICE DATE	COMMENT	GROSS	DEDUCTIONS	AMOUNT PAID
MAY291992	050192		7,500.00	.00	7,500.00

DETACH BEFORE DEPOSITING

DESTEC ENERGY

Bank One, Texas, N.A.
Houston, Texas

CHECK NUMBER [redacted]

DATE	AMOUNT
06/03/92	$*****7,500.00

PAY
SEVEN THOUSAND FIVE HUNDRED AND 00/100 **

Destec Energy Inc.

TO THE ORDER OF:

130956 FLORIDA DEPT OF ENVIRONMENTAL
REGULATION
2600 BLAIRSTONE RD
TALLAHASEE, FL 32399-2400

R Dennis Marston

[redacted]

DESTEC ENGINEERING

RECEIVED
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1992 JUN 15 AM 9: 39

HOUSTON, TEXAS

June 12, 1992

RECEIVED
JUN 15 1992
Bureau of
Air Regulation

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

Re: Central Florida Power Limited Partnership

Dear Clair:

Please find enclosed five copies of air construction permit application and prevention of significant deterioration analysis for a 206-MW cogeneration facility. A fee of $7,500 is enclosed to cover the appropriate permit fees for the facility. Disk and paper copies of the computer printouts of the air quality modeling results are included. The engineering calculations of the emission rates are presented in Appendix A. Also, a disk copy of these calculations has been included.

I will be contacting you in a few weeks to review the initial comments your staff my have. In the meantime, please call if you have any questions.

Sincerely,

Robert S. Chatham

Robert S. Chatham, P.E.
Senior Environmental Engineer

RSC/dmm

cc: Kennard F. Kosky, KBN
Barry Andrews, FDER
File (2)
M. Baig
C. Holladay, SW Dist.
B. Thomas
J. Harper, EPA
C. Shaver, NPS

12018C1/NKC1

#7500pd.
6-15-92
Rcpt.#180772

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

AC 53-214903
PSD-FL-190

RECEIVED
JUN 15 1992
Bureau of
Air Regulation

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: Central Florida Power 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) GT/HRSG Stack

SOURCE LOCATION: Street County Road 630 City 5 miles west of Ft. Meade

UTM: East 416.22 km Zone 17 North 3069.22 km

Latitude 27 ° 44 ' 46.7 "N Longitude 81 ° 51 ' 0.3 "W

APPLICANT NAME AND TITLE: Robert I. Taylor, Project Manager

APPLICANT ADDRESS: Suite 150, 2500 City West Blvd., Houston, Texas 77042

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Central Florida Power 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: R I Taylor

Robert I. Taylor, Project Manager
Name and Title (Please Type)

Date: 6/12/92 Telephone No. (713) 735-4330

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_

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: *6/12/92* 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 cogeneration facility. The power plant consists of one combustion turbine and an associated duct-burner-fired heat recovery steam generator (HRSG). See Sections 1.0 and 2.0 in PSD Application.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *6/1/93* Completion of Construction *1/1/95*

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 and water injection will be used to reduce air pollutant emissions.

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:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
	Not Applicable			

B. Process Rate, if applicable: (See Section V, Item 1)

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 2-1 and 2-2 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	
Refer to Tables 2-1							***See Figure 2-1***
and 2-2 in PSD Application							***in PSD Application***

[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) ***See Section VI of application.***
[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	
Refer to Tables in			
Appendix A of PSD			
Application			

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis: *(Typical)*

Percent Sulfur: *Natural gas--1 grain/100 CF; Oil--0.05%* Percent Ash: *<0.01% WGT*

Density: *7.1* lbs/gal Typical Percent Nitrogen: *0.03% WGT*

Heat Capacity: *Gas--21,515; oil--18,550* BTU/lb *131,700* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD Application*

F. If applicable, indicate the percent of fuel used for space heating. *Not applicable*

Annual Average *N.A.* Maximum *N.A.*

G. Indicate liquid or solid wastes generated and method of disposal.

Liquid and solid wastes will be disposed of in an approved manner.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: _180_ ft. Stack Diameter: _18.0_ ft.

Gas Flow Rate: _1,017,973_ ACFM _749,253_ DSCFM Gas Exit Temperature: _205_ °F.

Water Vapor Content: _7.3_ % Velocity: _66.7_ FPS

See Table A-6 in Appendix A of PSD Application. Data for a GE turbine, natural gas at 27°F shown above (maximum emission case).

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 in Appendix A in PSD Application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Tables in Appendix A 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 and Tables in Appendix A 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' guarantees form the basis of emission estimates (see Tables in Appendix A 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 2-2 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 *CT - Subpart GG; DB - Subpart Dc*

Contaminant	Rate or Concentration
CT: NO_x - oil firing	*100-107.9 ppmvd corrected to 15% O_2 & heat rate*
- natural gas firing	*101.9-104.9 ppmvd corrected to 15% O_2 & heat rate*
SO_2	*0.8% sulfur fuel*
DB: NO_x - natural gas firing	*No quantitative limits for natural gas firing.*

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). *N.A.*

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

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***

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1.0 INTRODUCTION

Central Florida Power Limited Partnership is proposing to construct and operate a nominal 206-megawatt (MW) cogeneration facility at the U.S. Agri-Chemicals Complex near Fort Meade, Florida. The facility is referred to as the Central Florida Cogeneration Plant. The Central Florida Cogeneration Plant is a combined cycle cogeneration power plant located on County Road 630 approximately 5 miles west of Fort Meade (see Figure 1-1). Destec Engineering, Inc. is under contract to the limited partnership to perform engineering services for the project, including air permitting. KBN Engineering and Applied Sciences, Inc. (KBN) has been contracted by Destec Engineering to provide air permitting services and perform air quality impact assessments for the project.

The plant will consist of one advanced technology heavy-duty industrial gas turbine (GT) electric generating unit, with a duct burner-fired heat recovery steam generator (HRSG) and one steam turbine generator. The GT will have a nominal electrical output of about 147 MW to the transmission system at average ambient conditions. The primary fuel for the GT is natural gas; distillate fuel oil will be used as the backup fuel. The GT uses advanced dry low NO_x combustors to limit nitrogen oxide (NO_x) emissions. Exhaust gas from the GT will be routed to a duct burner-fired HRSG. The natural gas-fired duct burner is expected to have a maximum heat input of about 100 million British thermal units per hour (MMBtu/hr). The steam from the HRSG will power a steam turbine to generate electrical power of no greater than 74 MW. Low-pressure steam will be exported to the U.S. Agri-Chemicals complex for process uses.

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 requirements 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.

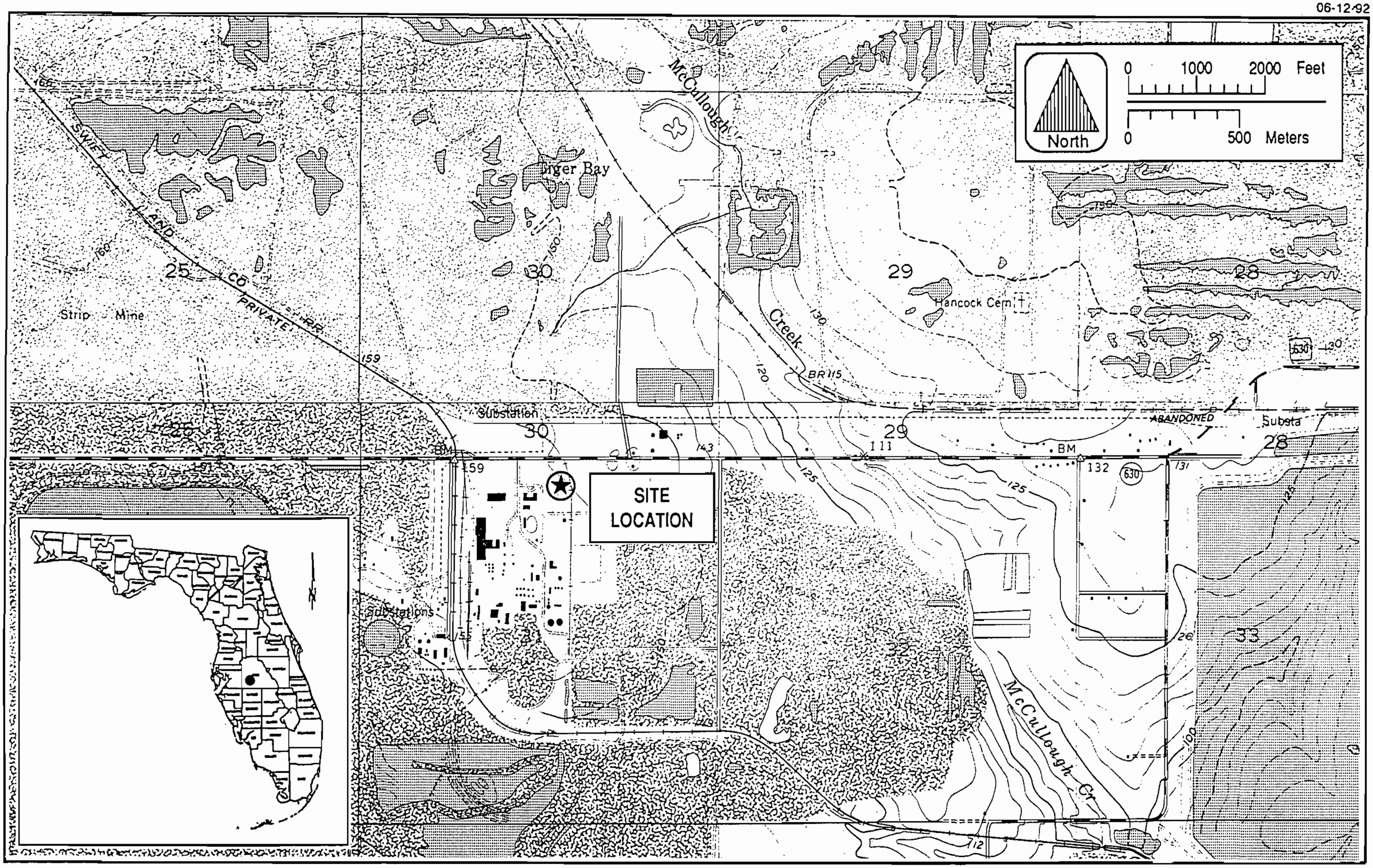


Figure 1-1 CENTRAL FLORIDA LIMITED PROJECT LOCATION MAP

SOURCE: USGS, 1986,1987; KBN, 1992.

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), volatile organic compounds (VOC), beryllium (Be), and arsenic (As). 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 U.S. Environmental Protection Agency's (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.

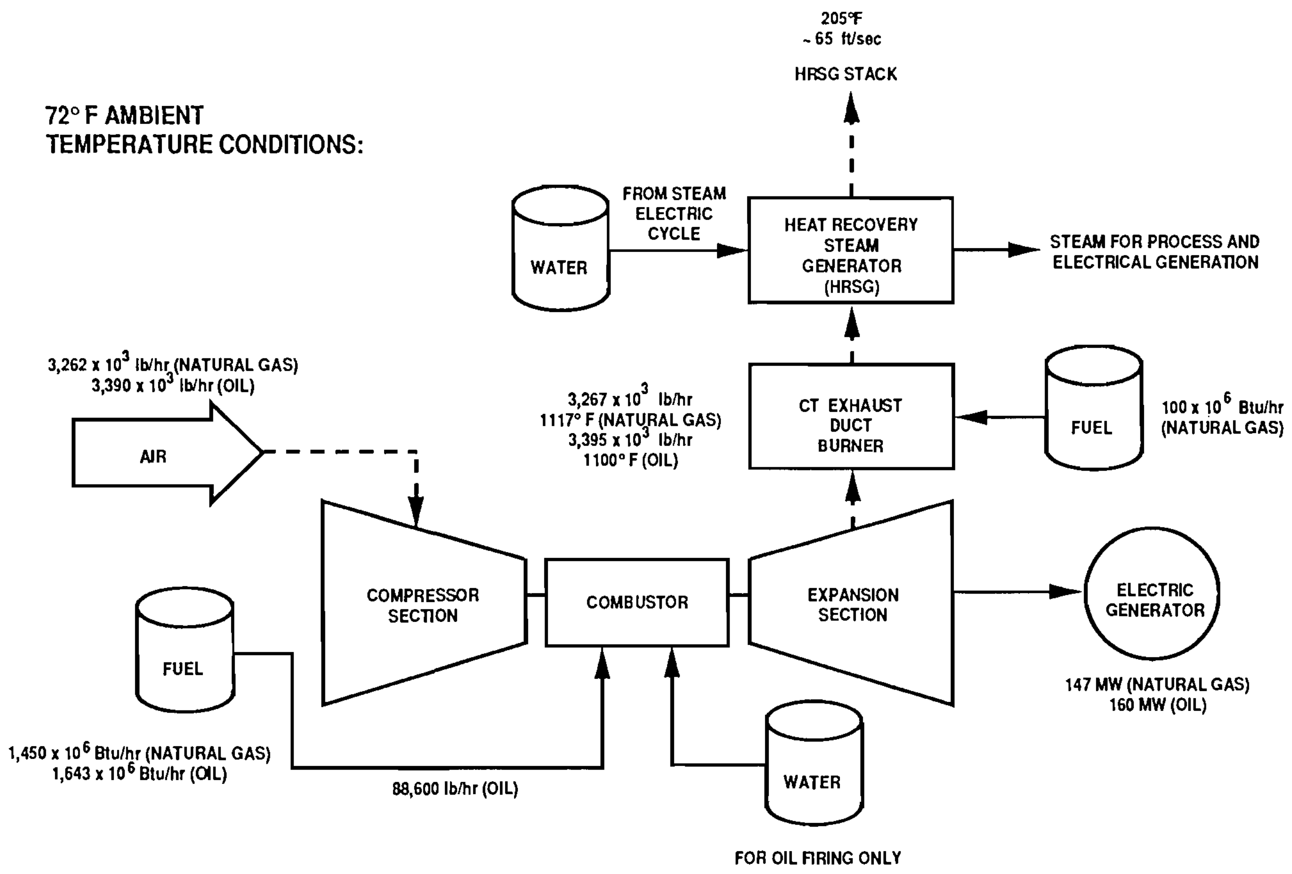
2.0 PROJECT DESCRIPTION

The Central Florida Cogeneration Plant will consist of one GT electrical generating unit, equipped with a duct burner-fired HRSG. The GT will be an advanced technology heavy-duty industrial gas turbine that will use advanced dry low-NO_x combustors to control NO_x emissions. The GT combustion gases will exhaust through the HRSG and into a single stack. There will be no bypass for simple cycle operation. A flow diagram is presented in Figure 2-1. Stack, operating, and emission data for the proposed combustion turbine are presented in Table 2-1. Emission data for the duct burner are presented in Table 2-2. Detailed information on the combustion calculations for the fuels to be fired in the GT and duct burner is presented in Appendix A. A plot plan of the facility is presented in Figure 2-2.

The GT/HRSG unit will be fired primarily with natural gas; distillate fuel oil will be used as the backup fuel for the GT. The annual distillate oil usage is anticipated to be no greater than 300 hours per year. The distillate oil will have an annual average sulfur content of 0.05 percent. The duct burner will be fired with natural gas only and is assumed to operate for 8,760 hours in a year.

The GT will have a nominal electrical output of about 147 MW and a maximum heat input of about 1,607 MMBtu/hr at average ambient conditions. The natural gas-fired duct burner will have a maximum heat input of 100 MMBtu/hr. The steam from the HRSG will power a steam turbine electrical generator with maximum output of about 74 MW. Low-pressure steam (approximately 40,000 lb/hr) will be exported to the U.S. Agri-Chemicals complex for process uses. Electrical power will be sold to the electric utility grid.

At this time, two types of advanced GTs are being considered for this project: General Electric (GE) PG7221 (FA) and Westinghouse 501F. Operating and emission data are available for these turbines for operating



NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED CENTRAL FLORIDA COGENERATION POWER PLANT

KBN

Table 2-1. Stack, Operating, and Emission Data for the Proposed Combustion Turbine

Parameter	Fuel Type[a] Natural Gas		Fuel Oil	
Stack Data (ft)				
Height	180		180	
Diameter	18		18	
Operating Data (72°F)[b]				
Temperature (°F)	205		205	
Velocity (ft/sec)	61.1		63.8	
Maximum Hourly Emission Data (lb/hr)/Fuel Type (27°F)[c]				
SO_2	4.86	(GE)	99.7	(GE)
PM	9.0	(GE)	40.4	(W)
NO_x	169.0	(W)	326.2	(GE)
CO	48.8	(GE)	163.5	(W)
VOC	8.0	(W)	18.9	(W)
Pb	Neg.		0.0165	(GE)
Sulfuric Acid Mist	0.63	(GE)	1.22	(GE)
F	Neg.		0.0602	(GE)
Be	Neg.		0.00462	(GE)
Hg	Neg.		0.00555	(GE)
As	Neg.		0.00777	(GE)
Annual Potential Emission Data (TPY)/Fuel Type (72°F)[c]				
SO_2	18.5	(GE)	13.3	(GE)
PM	38.1	(GE)	5.9	(W)
NO_x	614.8	(GE)	43.5	(GE)
CO	186.0	(GE)	23.6	(W)
VOC	29.8	(W)	2.7	(W)
Pb	Neg.		0.00219	(GE)
Sulfuric Acid Mist	2.38	(GE)	1.63	(GE)
F	Neg.		0.0080	(GE)
Be	Neg.		0.000616	(GE)
Hg	Neg.		0.000739	(GE)
As	Neg.		0.00104	(GE)

Note: GE = General Electric.
Neg. = negligible emissions for applicable pollutant.
W = Westinghouse.

[a] Refer to Appendix A for detailed information on each fuel. Annual emission data are based on the turbine firing fuel oil and natural gas for 300 and 8,460 hours, respectively. Tables A-1 through A-10 provide information on the GE machine while Tables A-19 through A-28 provide information on the Westinghouse machine.

[b] Does not account for additional exhaust flow from duct burner.

[c] Other regulated pollutants are assumed to have negligible emissions. These pollutants include reduced sulfur compounds, hydrogen sulfide, asbestos, vinyl chloride, and radionuclides.

Table 2-2. Emission Data for the Proposed Duct Natural Gas-Fired Burner

	Emissions[a] (Natural Gas Firing Only)
Maximum Hourly Emissions (lb/hr)[c]:	
SO_2	0.30
PM	1.00
NO_x	10.0
CO	10.0
VOC	2.90
Pb	Neg.
Sulfuric Acid Mist	0.0388
F	Neg.
Be	Neg.
Hg	Neg.
As	Neg.
Maximum Annual Emissions (TPY)[c]:	
SO_2	1.32
PM	4.38
NO_x	43.8
CO	43.8
VOC	12.7
Pb	Neg.
Sulfuric Acid Mist	0.170
F	Neg.
Be	Neg.
Hg	Neg.
As	Neg.

Note: Neg. = negligible emissions for applicable pollutant.

[a] Based on the duct burner operating for 8,760 hours at 100 MM Btu per hour and the following emission factors:
PM = 0.01 lb/MM Btu; SO_2 = 1 grain/100 cf of natural gas;
NO_x = 0.10 lb/MM Btu; CO = 0.10 lb/MM Btu; VOC = 0.029 lb/MM Btu, and
H_2SO_4 = 8% of SO_2

Tables A-11A through A-14A present duct burner emissions.

[c] Other regulated pollutants are assumed to have negligible or no emissions.

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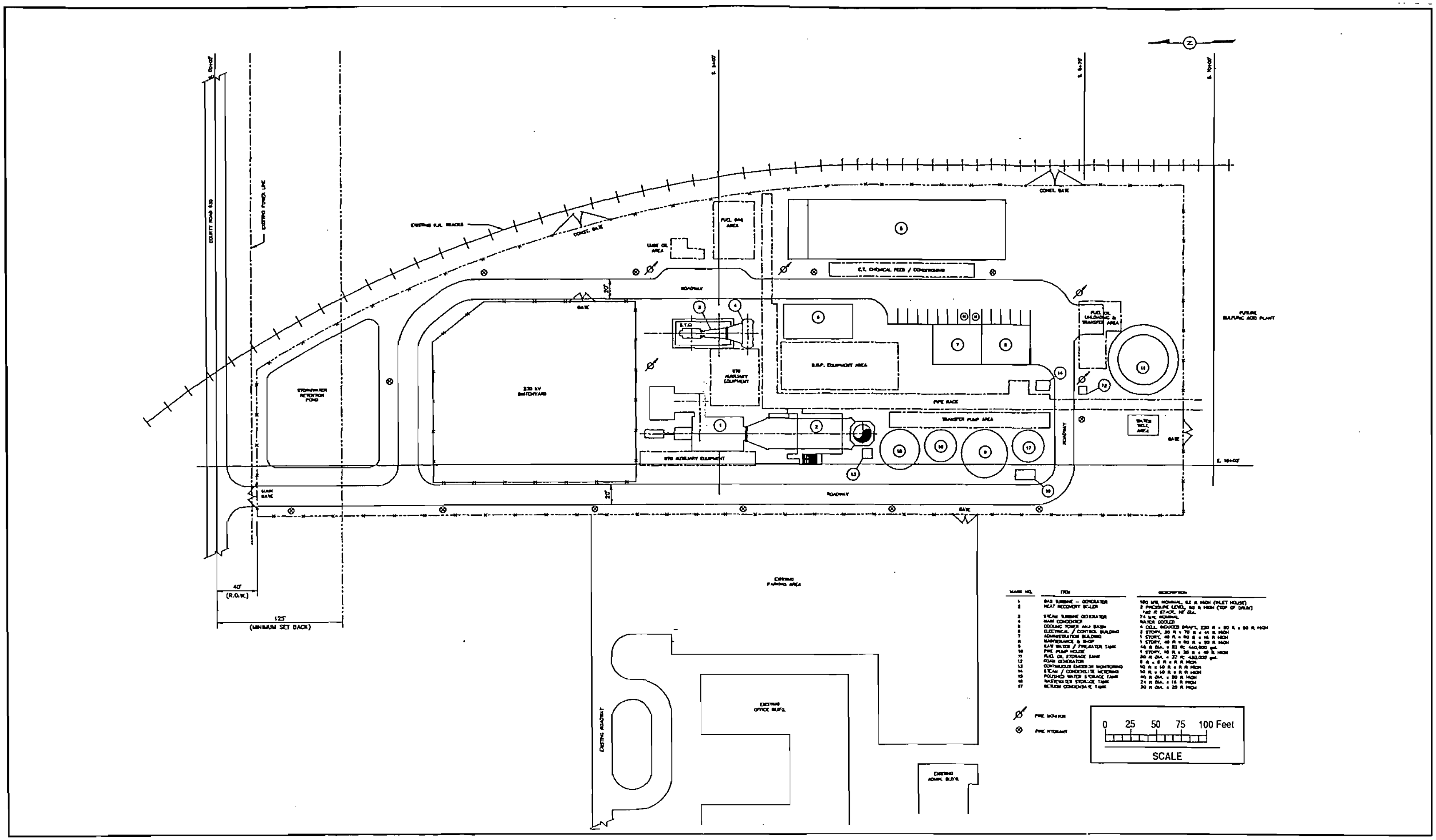

Figure 2-2 PLOT PLAN

KBN

loads of 100 and 70 percent and ambient temperatures ranging from 27 to 97 degrees Fahrenheit (°F).

Maximum hourly emissions occur for the lowest ambient temperature of 27°F when the GT is firing fuel oil. The hourly emission data for a given pollutant in Table 2-1 are based on the higher emission rate from either the GE or Westinghouse GT. The annual emissions are based on an ambient temperature of 72°F with GT firing fuel oil and natural gas for 300 and 8,460 hours, respectively. Similar to the maximum hourly emissions, the annual emissions are based on the higher emission rate from either type of GT.

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 gas turbine) can begin operation. The specific applicability of the proposed facility's maximum potential emissions and predicted impacts to air regulatory requirements for PSD, nonattainment, and hazardous pollutant reviews is presented in Section 3.1. General discussions concerning the AAQS, PSD review requirements, and nonattainment rules are presented in Sections 3.2 through 3.4.

3.1 SOURCE APPLICABILITY

3.1.1 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 120 km from the closest part of the Chassahowitzka National Wilderness Area, a PSD Class I area.

3.1.2 PSD REVIEW

3.1.2.1 Pollutant Applicability

As presented in Table 3-1, the proposed project is considered to be a major new source because emissions of any regulated pollutant will exceed 250 TPY; therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for PM(TSP), PM(PM10), NO_2, CO, VOC, Be, and inorganic As. Therefore, the project is subject to PSD review for these pollutants.

3.1.2.2 Ambient Monitoring

Based on the net increase in emissions from the proposed project, presented in Table 3-1, a PSD preconstruction ambient monitoring analysis is required for PM(TSP), PM(PM10), NO_2, CO, VOC (O_3), Be, and As. However, if the

Table 3-1. Net Increase in Emissions Due To the Central Florida Cogeneration Facility Compared to the PSD Significant Emission Rates

Pollutant	Emissions (TPY): Potential Emissions From Proposed Facility[a]	Emissions (TPY): Significant Emission Rate	Emissions (TPY): PSD Review
Sulfur Dioxide[b]	33.1	40	No
Particulate Matter (TSP)	45.0 (GE)	25	Yes
Particulate Matter (PM10)	45.0 (GE)	15	Yes
Nitrogen Dioxide	702.1 (GE)	40	Yes
Carbon Monoxide	243.1 (GE)	100	Yes
Volatile Organic Compounds	45.3 (W)	40	Yes
Lead	0.00219 (GE)	0.6	No
Sulfuric Acid Mist	4.2 (GE)	7	No
Total Fluorides	0.00802 (GE)	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	0.000616 (GE)	0.0004	Yes
Mercury	0.000739 (GE)	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	0.00104 (GE)	0	Yes

Note: GE = General Electric.
NEG = Negligible.
W = Westinghouse.

All calculations based on 72°F base load condition.

[a] Maximum annual emissions based on the gas turbine firing distillate oil and natural gas for 300 and 8,460 hours, respectively, and duct burner firing natural gas for 8,760 hours. Tables A-15 through A-18 present emissions for the GE machine while Tables A-33 through A-36 present emissions for the Westinghouse machine.

[b] Based on a maximum sulfur content specification of 0.05 percent in fuel oil.

predicted impact of a pollutant is less than the de minimis monitoring concentration, 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.

Maximum predicted modeling impacts as a result of the net increase associated with the proposed project are presented in Table 3-2 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 3-2, the maximum net increase in impact is below the respective de minimis monitoring concentration for all pollutants.

3.1.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The stack for the proposed turbine will be 180 feet (ft) (54.9 m). This stack height does not exceed the GEP stack height. The potential for downwash of the unit's emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.1.3 NONATTAINMENT REVIEW

The project site is located in Polk County, which is classified as an attainment area for all criteria pollutants. The plant is located approximately 20 km from Hillsborough County, a nonattainment area for ozone (O_3), and more than 50 km from any other nonattainment area. Therefore, nonattainment requirements are not applicable.

3.1.4 HAZARDOUS POLLUTANT REVIEW

The FDER has promulgated guidelines (FDER, 1991) to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. Each regulated pollutant for which an ambient standard does not exist and each nonregulated hazardous pollutant is to be compared to the applicable no-threat level (NTL). If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered

Table 3-2. Predicted Net Increase in Impacts Due To the Proposed Central Florida Cogeneration Facility Compared to PSD De Minimis Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$) Predicted Net Increase in Impacts	De Minimis Monitoring Concentration
Particulate Matter (TSP)	2.12	10, 24-hour
Particulate Matter (PM10)	2.12	10, 24-hour
Nitrogen Dioxide	0.29	14, annual
Carbon Monoxide	20.8	575, 8-hour
Volatile Organic Compounds	45.3 TPY	100 TPY
Beryllium	0.00021	0.001, 24-hour
Inorganic Arsenic	NA	NM

Note: NA = Not applicable.
NM = No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by EPA.
TPY = tons per year.

not to pose a significant health risk. The NTLs for pollutants applicable to the proposed project are presented in Table 3-3. Emissions for these pollutants are presented in Appendix A. As discussed in Section 7.0, the proposed project's impacts are predicted to be less than the applicable NTL and, therefore, are not expected to pose a health risk to the public.

3.2 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-4. 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.

3.3 PSD REQUIREMENTS

3.3.1 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. Under PSD regulations, 40 CFR 52.21, this proposed project is a "new source". PSD significant emission rates applicable to the project are shown in Table 3-5.

Table 3-3. Summary of Florida No-Threat Levels for Toxic Air Pollutants Applicable to the Proposed Facility Analysis

Pollutant	No-Threat Level ($\mu g/m^3$)		
	8-Hour	24-Hour	Annual
Antimony	5	1.2	0.3
Arsenic	2	0.48	0.00023
Barium	5	1.2	50
Beryllium	0.02	0.0048	0.00042
Cadmium	0.5	0.12	0.00056
Chlorine	15	3.6	NE
Chromium	5	1.2	1,000
Cobalt	0.5	0.12	NE
Copper	1	0.24	NE
Fluoride	2	0.48	50
Formaldehyde	4.5	1.08	0.077
Lead	1.5	0.36	0.09
Manganese	50	12	NE
Mercury	0.5	0.12	0.3
Nickel	0.5	0.12	0.0042
Polycyclic Organic Matter	NE	NE	NE
Selenium	2	0.48	NE
Sulfuric Acid Mist	10	2.38	NE
Vanadium	0.5	0.12	20
Zinc[a]	50	12	NE

Note: NE = none established.

[a] As zinc oxide.

Table 3-4. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Time	AAQS[a] National Primary Standard	AAQS[a] National Secondary Standard	AAQS[a] State of Florida	PSD Increments[a] Class I	PSD Increments[a] Class II	Significant Impact Levels[b]
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.

Table 3-5. PSD Significant Emission Rates and De Minimis Monitoring Concentrations Applicable to the Project

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)
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]
Beryllium	NESHAP	0.0004	0.001, 24-hour
Inorganic Arsenic	NESHAP	[c]	NM

[a] Short-term concentrations are not 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.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
TPY = tons per year.
$\mu g/m^3$ = micrograms per cubic meter.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

PSD review is used to determine whether significant air quality deterioration will result from the new 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 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,
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.

3.3.2 INCREMENTS/CLASSIFICATIONS

The proposed project is located in Polk County which is a PSD Class II area for SO_2, PM(TSP), and NO_x. All surrounding counties are also designated as PSD Class II areas. The project site is located approximately 120 km from the nearest PSD Class I area, the Chassahowitzka National Wilderness Area.

3.3.3 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 new facility exceeds the significant emission rate (see Table 3-1). The proposed project will be equipped with the most advanced dry low NO_x combustor design currently offered by GE or Westinghouse.

3.3.4 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. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts (see Table 3-1).

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 from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-5 [Chapter 17-2.500(3)(e), F.A.C.]. The proposed project's impacts will be less than the de minimis levels.

3.3.5 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 3-1). 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 source if the net increase in impacts as a result of the new source is below significance levels, as presented in Table 3-4.

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.

3.3.6 ADDITIONAL IMPACT ANALYSES

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 3-5).

3.3.7 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.

3.4 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities located in a nonattainment area must undergo nonattainment review. The nonattainment provisions do not apply since the proposed project is located in an attainment area for all pollutants.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to under go a control technology review for each pollutant that may potentially emit above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of PM/PM10, NO_x, CO, VOC, Be, and inorganic As (see Section 3.0). The emissions of these pollutants are:

Pollutant	Emissions (TPY)
NO_x	702.1
CO	243.1
VOC	45.3
PM/PM10	35.2
Beryllium	0.00062
Inorganic Arsenic	0.00104

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring the top-down approach. 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).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 ppmvd corrected for heat rate and 15 percent oxygen. For the GTs being considered for the project, the NSPS emission limit with the NSPS heat rate correction would range from 100 to 107.9 ppm on oil and from 101.9 to 104.9 ppm on gas (corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent). The applicable NSPS for the duct burner will be 40 CFR 60, Subpart Dc since the maximum heat input is $100x10^6$ Btu/hr. For natural gas firing, there are no quantifiable emission limitations for duct burners. More information on the NSPS is presented in Appendix B. The proposed emission limits for the project will be much lower than the NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

In recent permitting actions, FDER has established BACT for heavy-duty industrial gas turbines. These decisions have included the use of advanced dry low-NO_x combustors for limiting NO_x and CO emissions and clean fuels (natural gas and distillate oil). The proposed project will have two modes of operation for which a BACT analysis has been performed. The results of the analysis have concluded the following controls as BACT for the project.

1. GT--Natural Gas Fired. CFPLP is proposing to utilize state-of-the-art dry low-NO_x combustion technology which will achieve gas turbine exhaust NO_x levels of no greater than 25 parts per million or less on a dry basis (ppmvd) corrected to 15 percent O_2 and ISO conditions. CO emissions will be limited to 15 ppmvd.
2. GT--Fuel Oil Fired. CFPLP is proposing to utilize water injection to achieve gas turbine exhaust NO_x levels of no greater than 42 ppmvd corrected to 15 percent O_2 and ISO conditions. CO emissions will be limited to 50 ppmvd.

   It is possible that the advanced combustors may be able to achieve significantly lower NO_x levels. However, at this time, the ultimate levels achievable are not known due to the ongoing status of the technology development.
3. Duct Burner--Natural Gas Fired (Only). The propose NO_x/CO control technology for the duct burner is modern burner design, such that NO_x emission rates will not exceed 0.1 $lb/10^6$Btu (HHV) heat input and CO emission rates will not exceed 0.1 $lb/10^6$Btu. These proposed limits for natural gas firing are consistent with FDER's past and current BACT decisions for duct burners.

4.3.1 NITROGEN OXIDES

The BACT analysis was performed for the following alternatives:

1. Advanced dry low-NO_x combustors at an emission rate of 25 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil.
2. SCR and advanced dry low-NO_x combustors at an emission rate of approximately 9 ppmvd corrected to 15 percent O_2 when firing natural gas and 15 ppmvd when firing oil.

Appendix B presents a discussion of NO_x control technologies and their feasibility for the project.

As discussed in Section 2.1, the GT will be fired primarily with natural gas. Distillate oil will be used as backup fuel not to exceed 300 hours per year. The NO_x removed using SCR would be 28 TPY when firing oil and 428 TPY when firing natural gas; the later includes emissions from the duct burner.

4.3.1.1 Proposed BACT and Rationale

The proposed BACT for the project is advanced dry low-NO_x combustion technology. The proposed NO_x emissions level using this technology is 25 ppmvd (corrected to 15 percent oxygen and ISO conditions) when firing natural gas. 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 about $7,400 per ton of NO_x removed. These costs are in 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. The cost effectiveness is over $10,000 per ton of pollutant removed when the net emissions of all pollutants (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 7 million kWh per year.
4. The proposed BACT (i.e, dry low-NO_x combustion) provides the most cost effective control alternative, is pollution preventing and results in low environmental impacts (less than the significant impact levels). Dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to conventional GTs, the proposed BACT will result in 10 percent less NO_x emission from the same amount of generation. In addition, GT manufacturers have been willing to guarantee this level of NO_x emissions.
5. The proposed emission limit for duct firing (i.e., 0.1 lb/10^6 Btu) is BACT given the emission limits established on other projects.

The analyses of economic, environmental, and energy impacts follow.

4.3.1.2 Impacts Analysis

Economic--The total capital costs for SCR are $7,996,800. The total annualized cost of applying SCR with dry low-NO_x combustion is $3,364,400. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the dry low-NO_x combustors and water injection (for oil firing) is estimated to be $7,370/ton of NO_x removed.

Environmental--The maximum predicted impacts of the dry low-NO_x technology 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 maximum annual impact is 0.29 $\mu g/m^3$, which is 70 percent less than the significant impact level. While additional controls beyond dry low-NO_x combustors (i.e., SCR and SCR with water injection) would reduce predicted impacts, the effect will not be significant and much less than 1 percent of the PSD increment and the AAQS for the project.

The use of 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 up to 10 ppm based on reported experience; previous permit conditions have specified this level. Thus, the total, by volume, pollutant emissions using SCR would be about 80 percent of the proposed BACT level of 25 ppmvd. Indeed, ammonia emissions could be as high as 96 TPY. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM10; up to 71.1 TPY could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the project. This power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-1. This table shows the emissions balance for the project with and without SCR. As shown, the net reduction in emissions with SCR will be 233 TPY. In addition, emissions of carbon dioxide were included in Table 4-1 since this gas is under study as required in the 1990 Clean Air Act Amendments. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x combustion technology.

The replacement of the SCR catalyst will create additional economic and 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).

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

Table 4-1. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

	Project With SCR			Project Without SCR	
Pollutants	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	71 [c]	3.57	75	0	75
Sulfur Dioxide	0	39.27	39	0	39
Nitrogen Oxides	246 [d]	19.63	265	702	(437)
Carbon Monoxide	0	1.18	1	0	1
Volatile Organic Compounds	0	0.18	0	0	0
Ammonia	96 [e]	0.00	96	0	96
Total	413	63.83	476	702	(226)
Carbon Dioxide[f]	--	6,130	6,130	--	6,130

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 0.50 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 147 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 - 0.815 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 = 3.57 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 34.4 TPY SO_2 x 132 (MW of ammonia salt) ÷ 64 (MW of H_2SO_4).

[d] 9 ppm NO_x emissions on gas and 15 ppm NO_x emissions on oil; assumes 4% capacity factor on oil, the maximum proposed.

[e] 10 ppm ammonia slip (ideal gas law): 3,600,000 lb/hr x 10 ppm NH_3 x 17 ÷ 28 ÷ 10^6 x 4.38.

[f] Reflects differential emissions due to lost energy efficiency with SCR (i.e., 0.815 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 Btu/lb).

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--Significant energy penalties occur with SCR. With SCR, the output of the GT may be reduced by about 0.50 percent over that of advanced low-NO_x combustors. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 6,438,600 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 about 600 residential customers. To replace this lost energy, an additional 7×10^{10} British thermal units per year (Btu/yr) or about 70 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--CFPLP will use an advanced heavy-duty industrial gas turbine with advanced dry low-NO_x combustors. This type of machine advances the state-of-the-art for GTs by being more efficient and less polluting than previous GTs. Integral to the machine's design is 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.

An advanced machine is unique from an engineering perspective in two ways. First, advanced machine is larger and has higher firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the GE advanced machine is about 147 megawatts (MW), compared to conventional machines, which range from about 70 MW to 120 MW. The higher firing temperature [i.e., 2,350 degrees Fahrenheit (°F)] results in about 10 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines, which have firing temperatures of about 2,000°F. This has the added advantage of producing lower air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of dry low-NO_x combustors that will reduce NO_x emissions to 25 ppmvd corrected to 15 percent oxygen when firing natural gas. 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 GT 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 GT. The heat rate of the advanced GT will be about 9,900 Btu/kWh or better. In contrast, the heat rate for the conventional GT is about 11,000 Btu/kWh. The NO_x emission rate of the advanced GT, relative to the heat rate and NO_x emission rate of a conventional GT at 25 ppmvd corrected, is as follows:

Advanced GT - 22.5 ppmvd corrected to 15 percent O_2

Conventional GT - 25 ppmvd corrected to 15 percent O_2

Therefore, the NO_x emissions for an advanced GT will be 10 percent less than a conventional GT for the same amount of generation.

Also, the amount of NO_x control achieved by the dry low-NO_x combustor on an advanced GT is considerably higher than that achieved by a conventional machine as Table 4-2 illustrates. Since the advanced machine has higher firing temperatures, the NO_x emissions without the use of dry low-NO_x combustion technology are much higher. This results is an overall greater NO_x reduction on these machines.

4.3.2 CARBON MONOXIDE

Emissions of carbon monoxide (CO) are dependent upon the combustion design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing). The GTs proposed for the project have designs to optimize combustion efficiency and minimize CO as well as NO_x emissions.

For the project, the following alternatives were evaluated as BACT:

1. Combustion controls at 15 ppmvd; maximum annual CO emissions are 243 TPY (see Section 2.0), and
2. Oxidation catalyst at 10 ppmvd; maximum annual CO emissions are 172 TPY assuming 96.6 percent operation on gas and 3.4 percent operation on oil.

Table 4-2. NO_x Emissions Comparison of Conventional and Advanced Combustion Turbines

	Fuel	Units	NO_x Emissions Conventional	NO_x Emissions Advanced
Emissions Without Dry Low-NO_x Technology	Gas	ppmvd	150	179
	Oil	ppmvd	245	276
Emissions With Dry Low-NO_x Technology	Gas	ppmvd	25	25
	Oil	ppmvd	42	42
Reduction with Dry Low-NO_x Technology	Gas	ppmvd	125	154
		%	83	86
	Oil	ppmvd	203	234
		%	83	85

Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

4.3.2.1 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on GTs. The proposed BACT emission rates for CO would not exceed 15 ppmvd when firing natural gas and 50 ppmvd when firing distillate oil. 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 one million dollars, with a cost effectiveness of over $10,000/ton of CO removed).

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on GTs. 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 similar advanced combustion turbines have set limits in the 30 ppmvd range and higher. Even the Northeast State for Coordinated Air Use Management (NESCAUM) has recognized a BACT level of 50 ppmvd for CO emissions. The cost of an oxidation catalyst would be significant and not cost-effective given the maximum proposed emission limit of 15 ppmvd for the GT when firing gas and 50 ppmvd when firing distillate oil.

For the duct burner, the proposed BACT limit of 0.1 $lb/10^6$ Btu is lower than that adopted by FDER as BACT for similar projects (i.e., Lake and Pasco Cogeneration projects).

4.3.2.2 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $1,045,936, resulting in a cost effectiveness of over $10,000/ton of CO removed. The cost effectiveness is based on 96.6 percent operation on gas and 3.4 percent operation on oil, with the maximum emissions controlled to 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. Indeed, secondary emissions as a result of an oxidation catalyst will be about 29 TPY.

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 2,575,400 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 200 residential customers for a year. To replace this lost energy, about 2.6×10^{10} Btu/yr or about 26 million ft^3/yr of natural gas would be required.

4.3.3 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the GT 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 4.1 ppmvd when firing natural gas and 10.5 ppmvd when firing distillate oil. These emission levels are 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 GTs. The proposed VOC emission limits for the GT are in the range approved for other similar sources. The environmental effect of reduced emissions would not be significant.

4.3.4 PM/PM10 AND OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The emission of particulates from the GT is a result of incomplete combustion and trace elements in the fuel. Beryllium and inorganic arsenic would be included in the PM/PM10 emissions. The design of the GT 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 gas- or oil-fired GTs.

The maximum particulate emissions from the GT 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 40 pounds per hour (lb/hr) when firing natural gas]) 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 GTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for these pollutants.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas and distillate oil represent BACT because of their inherent low contaminant content.

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, VOC (O_3), Be, and As emissions. The maximum concentrations predicted for the proposed project compared to the PSD de minimis monitoring concentrations are presented in Table 5-1. Arsenic may be exempt from monitoring requirements because no acceptable monitoring technique has been established for that pollutant. However, 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 MODELING APPROACH

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

The general modeling approach for the proposed project follows EPA and FDER modeling guidelines. The highest predicted concentrations are compared with PSD significant impact levels, de minimis air quality levels, and Florida NTLs for toxic air pollutants. If the predicted impact from a facility exceeds the significant impact level for a particular pollutant, current policies stipulate that the highest annual average and highest, second-highest short-term (i.e., 24 hours or less) concentrations be compared with AAQS and PSD increments when 5 years of meteorological data are used.

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 highest concentration from the screening phase was produced. The air dispersion model then was executed for the entire year during which highest concentrations were predicted. 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, 1992a) was selected to evaluate the pollutant emissions from the proposed unit and other modeled sources. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1992b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

In this analysis, the ISCST2 model, Version 92062, was used to calculate both short-term and annual average concentrations because FDER and EPA have recommended this model for specific applications for an elevated emission source, such as that proposed for this project. Major features of the ISCST2 model are presented in Table 6-1.

The ISC 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.

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.

Table 6-1. Major Features of the ISCST2 Model

ISCST2 Model Features
• 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
• 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 with height of wind speed (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, 1992a.

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. The 5-year period of meteorological data, 1982 through 1986, is the data set recommended by FDER for emission sources in Polk County undergoing regulatory review.

The NWS station in Tampa, located approximately 70 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.

Mixing heights were calculated from the radiosonde data at Tampa 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). 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 Tables 6-2 and 6-3. The GT operating data are presented for both the GE and the Westinghouse turbines at 100 and 70 percent loads and 27 and 97°F ambient temperatures. For a given combination of operating load and ambient temperature, the lower exit velocities from the two types of turbines were selected to be modeled in order to maximize impacts. The exit gas velocities developed for burning natural gas were used because they were lower than those for fuel oil.

Table 6-2. Stack, Operating, and Emission Data Considered in the Air Quality Impact Modeling for the Proposed Facility

	General Electric Turbine				Westinghouse Turbine			
	100% Load		70% Load		100% Load		70% Load	
Parameter	27°F	97°F	27°F	97°F	27°F	97°F	27°F	97°F
Stack Data (ft)								
Height	180	180	180	180	180	180	180	180
Diameter	18	18	18	18	18	18	18	18
Operating Data								
Temperature (°F)	205	205	200	200	205	205	200	200
Velocity (ft/sec)	$\boxed{66.7^b}$	$\boxed{57.8^b}$	$\boxed{50.7^b}$	$\boxed{45.8^b}$	68.3	59.1	52.0	47.6

		General Electric Turbine[a]				Westinghouse Turbine[a]			
		100% Load		70% Load		100% Load		70% Load	
Parameter	Units	27°F	97°F	27°F	97°F	27°F	97°F	27°F	97°F
PM	lb/hr	18.0	18.0	18.0	18.0	$\boxed{41.4^c}$	$\boxed{37.7^c}$	$\boxed{35.2^c}$	$\boxed{30.2^c}$
	TPY	$\boxed{45.0^c}$	$\boxed{45.0^c}$	$\boxed{45.0^c}$	$\boxed{45.0^c}$	37.5	33.6	30.2	27.8
NO_2	TPY	777.5^c	$\boxed{655.2^c}$	623.3^c	$\boxed{528.4^c}$	$\boxed{802.5^c}$	644.0	$\boxed{629.8^c}$	509.4
CO	lb/hr	108.4	93.2	84.3	75.6	$\boxed{174.0^c}$	$\boxed{157.0^c}$	$\boxed{152.0^c}$	$\boxed{131.0^c}$

Note: Appendix A presents emissions and stack parameter information used to develop this table. 100 percent load refers to base load condition in the appendix tables.

[a] Short-term rates are based on burning distillate oil in the gas turbine and natural gas in the duct burner. Annual emission rates are based on burning distillate oil and natural gas for 300 and 8,460 hours, respectively, in the gas turbine and natural gas for 8,760 hours in the duct burner.

[b] Lower exit velocity of two turbine types burning natural gas for given operating load and ambient temperature; used in the modeling to produce maximum impacts for given operating load-ambient temperature combination. Does not include additional exhaust from duct burner.

[c] Higher emission rate of two turbine types for given operating load and ambient temperature; used in the modeling to produce maximum impacts.

Table 6-3. Emission Data for Other Regulated and Non-Regulated Pollutants Considered in the Air Quality Impact Modeling for the Proposed Facility

	Maximum Emission Rate (lb/hr)[a]			
	100% Load		70% Load	
Parameter	27°F	97°F	27°F	97°F
Antimony	4.04×10^{-2}	3.32×10^{-2}	3.23×10^{-2}	2.64×10^{-2}
Arsenic	7.77×10^{-3}	6.37×10^{-3}	6.20×10^{-3}	5.08×10^{-3}
Barium	3.61×10^{-2}	2.96×10^{-2}	2.88×10^{-2}	2.36×10^{-2}
Beryllium	4.62×10^{-3}	3.79×10^{-3}	3.69×10^{-3}	3.02×10^{-3}
Cadmium	1.94×10^{-2}	1.59×10^{-2}	1.55×10^{-2}	1.27×10^{-2}
Chlorine	4.99×10^{-2}	4.09×10^{-2}	3.98×10^{-2}	3.26×10^{-2}
Chromium	8.79×10^{-2}	7.21×10^{-2}	7.01×10^{-2}	5.75×10^{-2}
Cobalt	1.68×10^{-2}	1.38×10^{-2}	1.34×10^{-2}	1.10×10^{-2}
Copper	5.18×10^{-1}	4.25×10^{-1}	4.13×10^{-1}	3.39×10^{-1}
Fluoride	6.02×10^{-2}	4.94×10^{-2}	4.80×10^{-2}	3.94×10^{-2}
Formaldehyde	7.58×10^{-1}	6.23×10^{-1}	6.07×10^{-1}	4.99×10^{-1}
Lead	1.65×10^{-2}	1.35×10^{-2}	1.31×10^{-2}	1.08×10^{-2}
Manganese	2.59×10^{-2}	2.12×10^{-2}	2.07×10^{-2}	1.69×10^{-2}
Mercury	5.55×10^{-3}	4.55×10^{-3}	4.43×10^{-3}	3.63×10^{-3}
Nickel	3.14×10^{-1}	2.58×10^{-1}	2.51×10^{-1}	2.06×10^{-1}
Polycyclic Organic Matter	1.91×10^{-3}	1.61×10^{-3}	1.55×10^{-3}	1.31×10^{-3}
Selenium	4.33×10^{-2}	3.55×10^{-2}	3.46×10^{-2}	2.83×10^{-2}
Sulfuric Acid Mist	1.23×10^{1}	1.01×10^{1}	9.79×10^{0}	8.03×10^{0}
Vanadium	1.29×10^{-1}	1.05×10^{-1}	1.03×10^{-1}	8.41×10^{-2}
Zinc	1.26×10^{0}	1.04×10^{0}	1.01×10^{0}	8.26×10^{-1}

[a] Based on the General Electric turbine burning distillate oil, which produces the higher emission rates between the turbine types selected for this facility. Also includes emissions from the 100 MMBtu/hr duct burner.

The exit velocities are based on the exhaust from the turbine only and do not include the additional exhaust and, therefore, additional flow, from the duct burner. Also, the higher emission rate was selected for the specific operating load-ambient temperature combination to produce a conservative estimate of ambient impacts.

Modeling of the proposed facility demonstrated that the facility's maximum predicted PM, NO_2, and CO impacts are below the significant impact levels (see Section 7.1). Therefore, further modeling for these pollutants with background sources to determine impacts for comparison to AAQS and PSD Class II and I increments is not required.

6.4 RECEPTOR LOCATIONS

As discussed in Section 6.1.1, the general modeling approach considered screening and refined phases to address compliance with AAQS and PSD increments. For the screening phase, concentrations were predicted for 391 total receptors located in a radial grid centered at the proposed GT stack location (see Figure 6-1). These receptors were classified into two main groups:

1. 36 plant property receptors placed at the nearest plant boundary along 36 radials spaced at 10-degree increments. These receptors are presented in Table 6-4.
2. 355 general grid receptors located at distances of 100; 300; 500; 700; 1,000; 1,500; 2,000; 3,000; 4,000; and 5,000 m along 36 radials with each radial spaced at 10-degree increments.

After the screening modeling was completed, refined modeling was conducted using a receptor grid centered on the receptor that had the highest 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

06-11-92

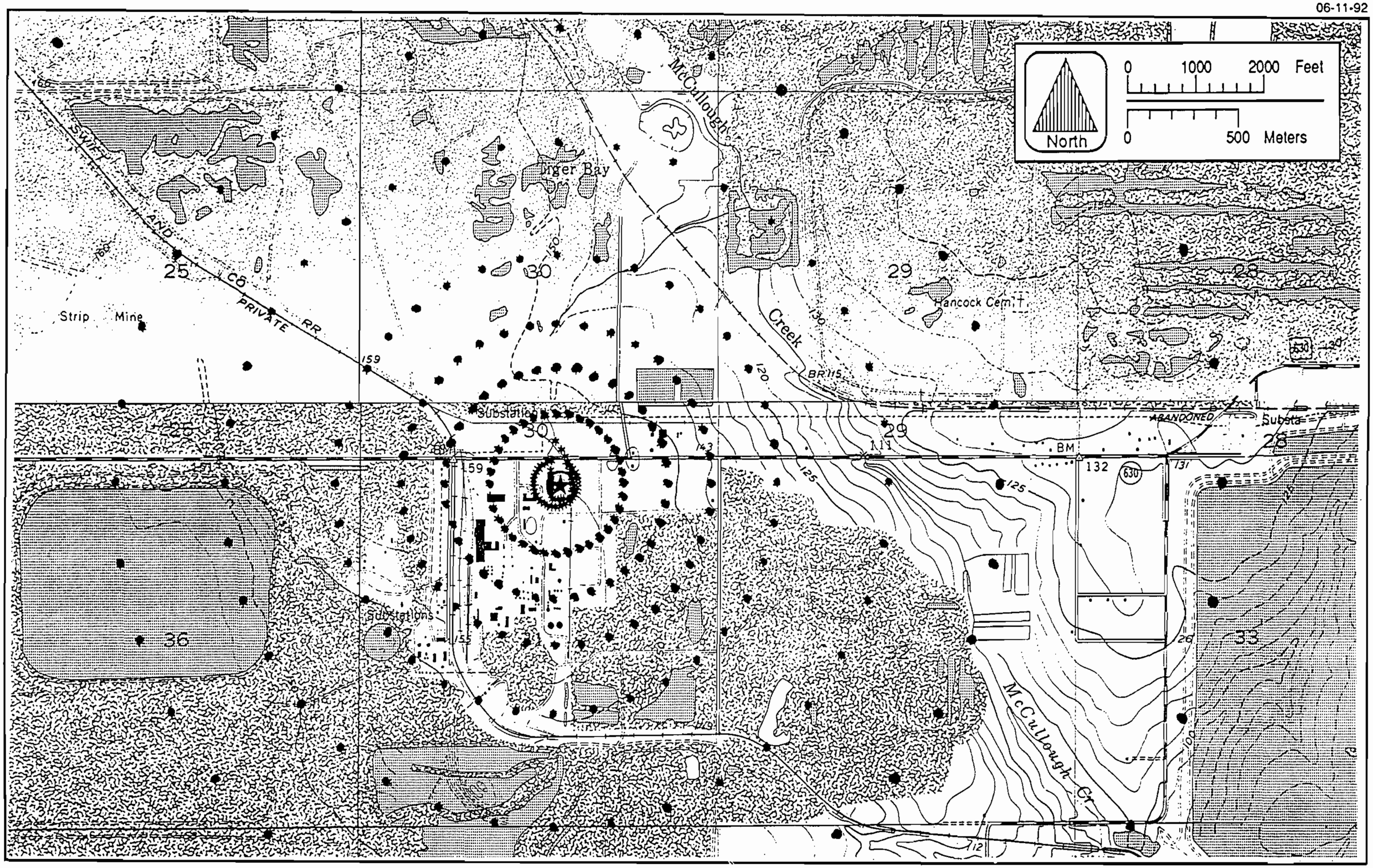

Figure 6-1 RECEPTOR LOCATIONS USED IN THE AIR QUALITY IMPACT ANALYSIS NEAR THE PROPOSED FACILITY

SOURCES: USGS, 1986, 1987; KBN, 1992.

KBN

Table 6-4. Plant Property Receptors Used in the Screening Modeling Analysis

Receptor Location		Receptor Location	
Direction (degrees)	Distance (meters)	Direction (degrees)	Distance (meters)
10	149	190	69
20	125	200	57
30	108	210	42
40	95	220	34
50	86	230	29
60	81	240	27
70	77	250	25
80	76	260	24
90	76	270	24
100	77	280	24
110	79	290	25
120	85	300	27
130	94	310	30
140	84	320	35
150	76	330	43
160	71	340	59
170	69	350	100
180	69	360	184

Note: Direction and distance are relative to the proposed GT stack.

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 (see Table 6-5). The highest predicted concentrations for the proposed facility for the 5 years of meteorological data were compared with the proposed PSD Class I significance values for PM and NO_2 (see Section 7.1.2).

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stack for the proposed GT will be less than GEP. Therefore, the potential for building downwash to occur was considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than H_b + 0.5 l_b, where H_b is the building

Table 6-5. Receptor Locations at the Chassahowitzka PSD Class I Area Used to Address the Proposed Facility's Impacts

Receptor Location UTM Coordinates (km)	
East	North
340.3	3165.7
340.3	3167.7
340.3	3169.8
340.7	3171.9
342.0	3174.0
343.0	3176.2
343.7	3178.3
342.4	3180.6
341.1	3183.4
339.0	3183.4
336.5	3183.4
334.0	3183.4
331.5	3183.4

height and l_b is the lesser of the building height or projected width), 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, and
2. Enhanced plume spread as a linear function of the effective plume height.

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. For both methods, the ISCST2 model uses direction-specific building dimensions for H_b and l_b for 36 radial directions, with each direction representing a 10-degree sector.

The building dimensions considered in the modeling analysis are presented in Table 6-6. The height of the GT stack is greater than $H_b + 0.5\ l_b$ but less than GEP. Therefore, the Huber-Snyder method was used for downwash calculations in the modeling analysis.

Table 6-6. Building Dimensions Used in the ISCST2 Modeling Analysis to Address Potential Building Downwash Effects for the Proposed Turbine's Stack

Direction (Degree)	Direction-Specific Building Data (m)	
	Height	Projected Width
10	27.43	15.28
20	27.43	18.44
30	27.43	21.03
40	27.43	23.00
50	27.43	24.26
60	27.43	24.78
70	27.43	24.80
80	27.43	24.49
90	27.43	23.58
100	27.43	24.55
110	27.43	24.80
120	27.43	24.76
130	27.43	24.16
140	27.43	22.83
150	27.43	20.80
160	27.43	18.14
170	27.43	14.93
180	NA	NA
190	27.43	15.28
200	27.43	18.44
210	27.43	21.03
220	27.43	23.00
230	27.43	24.26
240	27.43	24.78
250	27.43	24.80
260	27.43	24.49
270	27.43	23.58
280	27.43	24.55
290	27.43	24.80
300	27.43	24.76
310	27.43	24.16
320	27.43	22.83
330	27.43	20.80
340	27.43	18.14
350	27.43	14.93
360	NA	NA

Note: Based on the height, length, and width for heat recovery steam generator building of 27.43, 22.82, and 9.7 m, respectively.

NA = not applicable.

Table 7-2. Summary of Screening and Refined Air Modeling Impacts of Regulated Pollutants for the Central Florida Cogeneration Project (Page 1 of 2)

Operating Load (Percent)	Ambient Temperature (°F)	Pollutant	Averaging Period	Emission Rate Value	Emission Rate Units	Highest Predicted Concentration ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
SCREENING IMPACTS							
100	27	PM	24-Hour	41.4	lb/hr	0.63	5
			Annual	45.0	TPY	0.015	1
		NO_2	Annual	802.5	TPY	0.26	1
		CO	1-Hour	174.0	lb/hr	25.8	2000
			8-Hour	174.0	lb/hr	6.38	500
		Be	24-Hour	0.00462	lb/hr	0.000070	NA
100	97	PM	24-Hour	37.7	lb/hr	0.88	5
			Annual	45.0	TPY	0.017	1
		NO_2	Annual	655.2	TPY	0.25	1
		CO	1-Hour	157.0	lb/hr	29.8	2000
			8-Hour	157.0	lb/hr	10.5	500
		Be	24-Hour	0.00379	lb/hr	0.000089	NA
70	27	PM	24-Hour	35.2	lb/hr	1.59	5
			Annual	45.0	TPY	0.020	1
		NO_2	Annual	629.8	TPY	0.29	1
		CO	1-Hour	152.0	lb/hr	34.3	2000
			8-Hour	152.0	lb/hr	19.5	500
		Be	24-Hour	0.00369	lb/hr	0.00017	NA
70	97	PM	24-Hour	30.2	lb/hr	1.94	5
			Annual	45.0	TPY	0.022	1
		NO_2	Annual	528.4	TPY	0.26	1
		CO	1-Hour	131.0	lb/hr	33.0	2000
			8-Hour	131.0	lb/hr	19.4	500
		Be	24-Hour	0.00302	lb/hr	0.00019	NA

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

7.1.1 SIGNIFICANT IMPACT LEVELS

A summary of the maximum screening concentrations as a result of the proposed facility using a generic emission rate (i.e., 10 g/s) and operating at 100 percent and 70 percent load conditions and 27°F and 97°F ambient temperatures is presented in Table 7-1. Predicted screening and refinement impacts based on the maximum emission rates for each pollutant are presented in Table 7-2. The results are presented for all regulated pollutants to be considered in the modeling analysis. The modeling was performed based on the lowest exit velocity and highest emission rate of the two turbine types for each load and temperature (see Table 6-2). This approach ensures that the maximum impacts from the proposed facility will be obtained. Refinements were performed for the operating scenario producing the worst-case impacts (i.e., 70 percent load, 27 and 97°F ambient temperatures). Generic screening impacts for each year and averaging period are presented in Appendix C.

PM/PM10 Concentrations

The maximum predicted 24-hour and annual average PM(TSP) concentrations due to the proposed facility are 2.12 and 0.022 $\mu g/m^3$, respectively. Maximum PM10 impacts are assumed to be identical to the PM(TSP) impacts. Since these maximum concentrations are below the 24-hour and annual significance levels of 5 and 1 $\mu g/m^3$ and 24-hour de minimis level of 10 $\mu g/m^3$ for these pollutants, no further modeling analysis is necessary.

NO_2 Concentrations

The maximum predicted annual NO_2 concentration due to the proposed facility is 0.29 $\mu g/m^3$. Because this level of impact is below the annual significance level of 1 $\mu g/m^3$ and annual de minimis level of 14 $\mu g/m^3$, no further modeling analysis was performed.

Table 7-1. Summary of Generic Screening Air Modeling Impacts for the Central Florida Cogeneration Project

Operating Load (Percent)	Ambient Temperature (°F)	Exit Velocity (ft/s)	Averaging Period	Generic Concentration ($\mu g/m^3$)[a]	Location and Time Period of Maximum Concentration: Receptor Location: Direction (degrees)	Distance (meters)	Time Period: Year	Month	Day	Hour Ending
SCREENING IMPACTS										
100	27	66.7	1-hour	11.8	100	300	84	3	29	8
			3-hour	6.49	120	300	82	1	14	15
			8-hour	2.91	250	2000	84	6	12	16
			24-hour	1.21	90	2000	86	8	18	24
			Annual	0.11	90	2000	86	--	--	--
100	97	57.8	1-hour	15.1	220	300	84	8	17	4
			3-hour	8.20	120	300	82	1	14	15
			8-hour	5.33	120	300	84	3	29	16
			24-hour	1.86	130	300	84	2	28	24
			Annual	0.13	90	2000	86	--	--	--
70	27	50.7	1-hour	17.9	220	300	84	8	17	4
			3-hour	14.0	120	300	84	3	29	12
			8-hour	10.2	120	300	84	3	29	16
			24-hour	3.58	120	300	84	3	29	24
			Annual	0.16	90	2000	86	--	--	--
70	97	45.8	1-hour	20.0	220	300	84	8	17	4
			3-hour	16.1	120	300	84	3	29	12
			8-hour	11.7	120	300	84	3	29	16
			24-hour	5.09	130	300	84	2	28	24
			Annual	0.17	90	2000	86	--	--	--

Note: Highest concentrations reported for all averaging periods.

[a] Based on modeling at a generic emission rate of 10.0 grams per second.

Table 7-2. Summary of Screening and Refined Air Modeling Impacts of Regulated Pollutants for the Central Florida Cogeneration Project (Page 2 of 2)

Operating Load (Percent)	Ambient Temperature (°F)	Pollutant	Averaging Period	Emission Rate Value	Emission Rate Units	Highest Predicted Concentration ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
REFINED IMPACTS[a]							
70	97	PM	24-Hour	30.2	lb/hr	2.12	5
			Annual	45.0	TPY	0.022	1
70	27	NO_2	Annual	629.8	TPY	0.29	1
70	27	CO	1-Hour	152.0	lb/hr	45.8	2000
			8-Hour	152.0	lb/hr	20.8	500
70	97	Be	24-Hour	0.00302	lb/hr	0.00021	NA

Note: Highest concentrations reported for all averaging periods.
NA = not applicable.

[a] Based on the refined modeling results using an emission rate of 10 g/s:

1-hour, 27.7 $\mu g/m^3$
3-hour, 16.6 $\mu g/m^3$
8-hour, 12.6 $\mu g/m^3$
24-hour, 5.58 $\mu g/m^3$
Annual, 0.173 $\mu g/m^3$

CO Concentration

The maximum predicted 1- and 8-hour average CO concentrations due to the proposed facility are 45.8 and 20.8 $\mu g/m^3$, respectively. Because the maximum predicted impacts due to the proposed facility are less than the 1- and 8-hour significance levels of 2,000 and 500 $\mu g/m^3$ and the 8-hour de minimis level of 575 $\mu g/m^3$, additional modeling is not required for this pollutant.

Be Concentration

The maximum 24-hour Be concentration due to the proposed facility is predicted to be 0.00021 $\mu g/m^3$. No significance level has been established for Be, but a de minimis monitoring concentration has been set at 0.001 $\mu g/m^3$, 24-hour average. Since the predicted impacts due to the proposed facility only are well below the de minimis, no further PSD modeling analysis was conducted. Beryllium was addressed as a toxic air pollutant for comparison to the Florida NTLs (refer to Section 7.1.3).

As Concentration

No significance levels have been established for As. There is also no ambient measurement method established for As and, thus, no de minimis monitoring concentration. Therefore, no further PSD modeling analysis was conducted. Arsenic was addressed as a toxic air pollutant for comparison to the Florida NTLs (refer to Section 7.1.3).

7.1.2 PSD CLASS I SIGNIFICANCE ANALYSIS

Maximum PM and NO_2 concentrations predicted at the PSD Class I area of the Chassahowitzka National Wildlife Area using a generic emission rate of 10 g/s are presented in Table 7-3. Detailed generic impacts for each year and averaging period are presented in Appendix C.

Predicted PM and NO_2 impacts using maximum emission rates for comparison to the National Park Service (NPS) recommended Class I significance values are presented in Table 7-4. Impacts are presented using the lowest exit velocity and highest emission rate for the two turbine types for each load and temperature (see Table 6-2). As shown, the maximum predicted PM

Table 7-3. Summary of Maximum Predicted Generic Concentrations Due to the Proposed Project at the Chassahowitzka NWA

Operating Load (Percent)	Ambient Temperature (°F)	Exit Velocity (ft/s)	Averaging Period	Generic Concentration (μg/m3)[a]	Location and Time Period of Maximum Concentration: Receptor Location: UTM East (meters)	UTM North (meters)	Time Period: Year	Month	Day	Hour Ending
100	27	66.7	24-hour	0.088	340700	3171900	86	12	10	24
			Annual	0.0059	340300	3165700	82	--	--	--
100	97	57.8	24-hour	0.090	340700	3171900	86	12	10	24
			Annual	0.0060	340300	3165700	82	--	--	--
70	27	50.7	24-hour	0.092	340700	3171900	86	12	10	24
			Annual	0.0063	340300	3165700	82	--	--	--
70	97	45.8	24-hour	0.094	340700	3171900	86	12	10	24
			Annual	0.0064	340300	3165700	82	--	--	--

[a] Based on modeling at a generic emission rate of 10.0 grams per second.

Table 7-4. Summary of Maximum Predicted PM and NO_2 Concentrations Due to the Proposed Project at the Chassahowitzka NWA

Operating Load (Percent)	Ambient Temperature (°F)	Pollutant	Averaging Period	Emission Rate Value	Emission Rate Units	Highest Predicted Concentration ($\mu g/m^3$)	NPS Recommended Significance Level ($\mu g/m^3$)
100	27	PM	24-Hour	41.4	lb/hr	0.046	0.33
			Annual	45.0	TPY	0.0008	0.1
		NO_2	Annual	802.5	TPY	0.014	0.025
100	97	PM	24-Hour	37.7	lb/hr	0.043	0.33
			Annual	45.0	TPY	0.0008	0.1
		NO_2	Annual	655.2	TPY	0.011	0.025
70	27	PM	24-Hour	35.2	lb/hr	0.041	0.33
			Annual	45.0	TPY	0.0008	0.1
		NO_2	Annual	629.8	TPY	0.011	0.025
70	97	PM	24-Hour	30.2	lb/hr	0.036	0.33
			Annual	45.0	TPY	0.0008	0.1
		NO_2	Annual	528.4	TPY	0.010	0.025

Note: Highest concentrations reported for all averaging periods.

24-hour and annual impacts are 0.046 and 0.0008 $\mu g/m^3$, respectively. These impacts are well below the NPS significance values of 0.33 and 0.10 $\mu g/m^3$.

The maximum predicted annual NO_2 concentration is 0.014 $\mu g/m^3$ which is below the NPS significance value 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 modeled pollutants. Therefore, no further Class I modeling analysis was conducted.

7.1.3 TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility are presented in Table 7-5. These impacts are based on the refined 24-hour impacts modeled for the 70 percent load, 97°F case and the refined 1-hour and annual impacts for the 70 percent load (27°F case), since these cases produced the highest impacts for the respective averaging periods (see Table 7-2).

The maximum 8-hour, 24-hour, and annual concentrations are compared in Table 7-5 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 health risk to the public.

7.2 ADDITIONAL IMPACT ANALYSES

7.2.1 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

Table 7-5. Summary of Maximum Concentrations Due to the Proposed Facility For the Air Toxic Modeling Analysis (Page 1 of 2)

Pollutant	Averaging Period	Maximum Concentration (μg/m3)[a]	Florida No Threat Level (μg/m)
Antimony	8-hour	0.0042	5
	24-hour	0.0019	1.2
	Annual	0.000058	0.3
Arsenic	8-hour	0.00081	2
	24-hour	0.00036	0.48
	Annual	0.000011	0.00023
Barium	8-hour	0.0037	5
	24-hour	0.0017	1.2
	Annual	0.000052	50
Beryllium	8-hour	0.00048	0.02
	24-hour	0.00021	0.0048
	Annual	0.000007	0.00042
Cadmium	8-hour	0.0020	0.5
	24-hour	0.00089	0.12
	Annual	0.000028	0.00056
Chlorine	8-hour	0.0052	15
	24-hour	0.0023	3.6
	Annual	0.000071	NE
Chromium	8-hour	0.0091	5
	24-hour	0.0040	1.2
	Annual	0.00013	1000
Cobalt	8-hour	0.0017	0.5
	24-hour	0.00077	0.12
	Annual	0.000024	NE
Copper	8-hour	0.054	1
	24-hour	0.024	0.24
	Annual	0.00074	NE
Fluoride	8-hour	0.0063	2
	24-hour	0.0028	0.48
	Annual	0.000086	50
Formaldehyde	8-hour	0.079	4.5
	24-hour	0.035	1.08
	Annual	0.0011	0.077

Table 7-5. Summary of Maximum Concentrations Due to the Proposed Facility For the Air Toxic Modeling Analysis (Page 2 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m3$)[a]	Florida No Threat Level ($\mu g/m$)
Lead	8-hour	0.0017	1.5
	24-hour	0.00076	0.36
	Annual	0.000024	0.09
Manganese	8-hour	0.0027	50
	24-hour	0.0012	12
	Annual	0.000037	NE
Mercury	8-hour	0.00058	0.5
	24-hour	0.00026	0.12
	Annual	0.000008	0.3
Nickel	8-hour	0.033	0.5
	24-hour	0.014	0.12
	Annual	0.00045	0.0042
Polycyclic Organic Matter	8-hour	0.00021	NE
	24-hour	0.000092	NE
	Annual	0.000003	NE
Selenium	8-hour	0.0045	2
	24-hour	0.0020	0.48
	Annual	0.000062	NE
Sulfuric Acid Mist[b]	8-hour	1.3	10
	24-hour	0.56	2.38
	Annual	0.018	NE
Vanadium	8-hour	0.013	0.5
	24-hour	0.0059	0.12
	Annual	0.00018	20
Zinc[c]	8-hour	0.13	50
	24-hour	0.058	12
	Annual	0.0018	NE

Note: NE = none established.

[a] 24-hour concentrations reported are the maximum refined impacts for the 70 percent load, 97°F case; 1-hour and annual concentrations from the refined impacts for the 70 percent load, 27°F case.

[b] Not in current FDER NTL list. NTL in table is based on dividing the time-weighted average by 100 and 420 for the 8-hour and 24-hour NTL, respectively.

[c] As zinc oxide.

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 are less than the significant impact levels (see Table 7-4). As a result, no impacts are expected to occur to vegetation as a result of the proposed emissions of these pollutants.

7.2.2 IMPACTS TO SOILS

SO_2 that reaches the soil by deposition from the air is converted by physical and biotic processes to sulfates. (Particulates have no affect on soils at the levels predicted.) The effects can be beneficial to plants if sulfates in native soils are less than plant requirements for optimum growth. However, sulfates can also increase acidity of unbuffered soils, causing adverse effects due to changes in nutrient availability and cycling. The predicted concentrations of SO_2 from stack emissions are not expected to have a significant adverse effect on soils in the vicinity because:

1. The predicted concentrations are low; and
2. Fertilizer and gypsum is generally applied to lands being used for crops, pasture, and citrus.

Therefore, the facility is not expected to have a significant adverse impact on regional vegetation or soils.

7.2.3 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel may be added to the current plant personnel complement. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in Polk County.

7.2.4 IMPACTS TO VISIBILITY

The Central Florida Cogeneration Plant is located approximately 120 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 particulate emissions for the Westinghouse turbine at base load and 27°F ambient temperature and nitrogen dioxide emissions for the GE turbine at base load and 27°F ambient temperature were used in order to maximize impacts at the Class I area. The results of the screening analysis are presented in Table 7-6. Based on these results, the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-6. Visibility Analysis for the Central Florida Cogeneration Facility on the PSD Class I Area

Visual Effects Screening Analysis for
Source: CENTRAL FLORIDA COGENERATION FACILITY
Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	41.40	lb/hr
NOx (as NO2)	336.20	lb/hr
Primary NO2	.00	lb/hr
Soot	.00	lb/hr
Primary SO4	.00	lb/hr

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	120.00 km
Min. Source-Class I Distance:	120.00 km
Max. Source-Class I Distance:	152.00 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.	120.0	84.	2.00	.023	.05	.000
SKY	140.	84.	120.0	84.	2.00	.006	.05	-.000
TERRAIN	10.	84.	120.0	84.	2.00	.001	.05	.000
TERRAIN	140.	84.	120.0	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.	116.2	94.	2.00	.024	.05	.000
SKY	140.	75.	116.2	94.	2.00	.006	.05	-.000
TERRAIN	10.	60.	109.7	109.	2.00	.001	.05	.000
TERRAIN	140.	60.	109.7	109.	2.00	.000	.05	.000

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ATTACHMENT 4

DETAILED EMISSION CALCULATIONS FOR THE COMBUSTION TURBINE

GE7FATR1
7/21/92

Table A-1. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A B	C	D	E	F	G
General					
Power (kW)	183,700.0		159,200.0		142,500.0
Heat Rate (Btu/kwh)	10,070.0		10,320.0		10,650.0
CT Exhaust Flow					
Mass Flow (lb/hr)	3,743,000		3,390,000		3,189,000
Temperature (oF)	1,060		1,102		1,127
Moisture (% Vol.)	11.59		12.40		12.71
Oxygen (% Vol.)	10.96		10.95		11.03
Molecular Weight	28.25		28.15		28.10
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu					
Power (kW)	183,700.0		159,200.0		142,500.0
Heat Rate (Btu/kwh)	10,070.0		10,320.0		10,650.0
Heat Input (MMBtu/hr)	1,849.9		1,642.9		1,517.6
Fuel Oil Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)					
Heat Input (MMBtu/hr)	1,849.9		1,642.9		1,517.6
Heat Content,LHV (Btu/lb)	18,550		18,550		18,550
Fuel Oil (lb/hr)	99,722.9		88,568.4		81,812.7
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)	3,743,000		3,390,000		3,189,000
Temperature (°F)	1,060		1,102		1,127
Molecular Weight	28.25		28.15		28.10
Volume Flow (acfm)	2,450,287		2,288,314		2,190,589
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)	3,743,000		3,390,000		3,189,000
Temperature (°F)	68		68		68
Molecular Weight	28.25		28.15		28.10
Volume Flow (scfm)	851,152		773,514		728,816
HRSG Stack Data					
Stack Height (ft)	180		180		180
Diameter (ft)	18.0		18.0		18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]					
Volume Flow (acfm) from CT	2,450,287		2,288,314		2,190,589
CT Temperature (°F)	1,060		1,102		1,127
HRSG Temperature (°F)	205		205		205
Volume Flow (acfm) from HRSG	1,072,001		974,218		917,922
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)^2÷ 4) x 3.14159] ÷ 60 sec/min					
Volume Flow (acfm) from HRSG	1,072,001		974,218		917,922
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	70.2		63.8		60.1

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: General Electric, 1992.

Table A-2. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		17.0		17.0		17.0
lb/hr		17.0		17.0		17.0
TPY		2.6		2.6		2.6
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2/lb S) x fraction emitted as SO2						
Fuel Oil (lb/hr)		99,722.9		88,568.4		81,812.7
Sulfur content (%)		0.05		0.05		0.05
lb SO2/lb S (64/32)		2.0		2.0		2.0
SO2 Fraction emitted		1.00		1.00		1.00
lb/hr		99.72		88.57		81.81
TPY		15.0		13.3		12.3
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		42.0		42.0		42.0
Moisture (%)		11.59		12.4		12.71
Oxygen (%)		10.96		10.95		11.03
Volume Flow (acfm)		2,450,287		2,288,314		2,190,589
Temperature (°F)		1060		1102		1127
lb/hr		326.2		290.2		268.0
TPY		48.9		43.5		40.2
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+ (1)		30.0		30.0		30.0
Moisture (%)		11.59		12.4		12.71
Volume Flow (acfm)		2,450,287		2,288,314		2,190,589
Temperature (°F)		1060		1102		1127
lb/hr		98.4		88.6		83.2
TPY		14.8		13.3		12.5
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		4.0		3.9		4.1
Moisture (%)		11.59		12.4		12.71
Volume Flow (acfm)		2,450,287		2,288,314		2,190,589
Temperature (°F)		1060		1102		1127
lb/hr		7.50		6.58		6.50
TPY		1.1		1.0		1.0
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (2)		8.9		8.9		8.9
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		1.65E-02		1.46E-02		1.35E-02
TPY		2.47E-03		2.19E-03		2.03E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) General Electric, 1992; (2) EPA, 1990

Table A-3. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Arsenic (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)		4.2		4.2		4.2
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		7.77E-03		6.90E-03		6.37E-03
TPY		1.17E-03		1.04E-03		9.56E-04
Beryllium (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)		2.5		2.5		2.5
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		4.62E-03		4.11E-03		3.79E-03
TPY		6.94E-04		6.16E-04		5.69E-04
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)		3		3		3
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		5.55E-03		4.93E-03		4.55E-03
TPY		8.32E-04		7.39E-04		6.83E-04
Fluoride (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (2)		14		14		14
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		6.02E-02		5.35E-02		4.94E-02
TPY		9.03E-03		8.02E-03		7.41E-03
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8		8		8
SO2 (lb/hr)		99.7		88.6		81.8
lb H2SO4/lb SO2 (98/64)		1.53		1.53		1.53
lb/hr		1.22E+01		1.08E+01		1.00E+01
TPY		1.83E+00		1.63E+00		1.50E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-4. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Manganese (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)		14		14		14
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		2.59E-02		2.30E-02		2.12E-02
TPY		3.88E-03		3.45E-03		3.19E-03
Nickel (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)		170		170		170
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		3.14E-01		2.79E-01		2.58E-01
TPY		4.72E-02		4.19E-02		3.87E-02
Cadmium (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)		10.5		10.5		10.5
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		1.94E-02		1.73E-02		1.59E-02
TPY		2.91E-03		2.59E-03		2.39E-03
Chromium (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)		47.5		47.5		47.5
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		8.79E-02		7.80E-02		7.21E-02
TPY		1.32E-02		1.17E-02		1.08E-02
Copper (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)		280		280		280
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		5.18E-01		4.60E-01		4.25E-01
TPY		7.77E-02		6.90E-02		6.37E-02
Vanadium (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)		69.5		69.5		69.5
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		1.29E-01		1.14E-01		1.05E-01
TPY		1.93E-02		1.71E-02		1.58E-02
Selenium (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)		23.42		23.42		23.42
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		4.33E-02		3.85E-02		3.55E-02
TPY		6.50E-03		5.77E-03		5.33E-03
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)		0.278		0.278		0.278
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		5.14E-04		4.57E-04		4.22E-04
TPY		7.71E-05		6.85E-05		6.33E-05
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)		405		405		405
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		7.49E-01		6.65E-01		6.15E-01
TPY		1.12E-01		9.98E-02		9.22E-02

Source: (1) EPA, 1990

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Antimony (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		9.4		9.4		9.4
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		4.04E-02		3.59E-02		3.32E-02
TPY		6.06E-03		5.38E-03		4.97E-03
Barium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		8.4		8.4		8.4
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		3.61E-02		3.21E-02		2.96E-02
TPY		5.42E-03		4.81E-03		4.44E-03
Cobalt (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		3.9		3.9		3.9
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		1.68E-02		1.49E-02		1.38E-02
TPY		2.51E-03		2.23E-03		2.06E-03
Zinc (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		294		294		294
HIR (MMBtu/hr)		1,849.9		1,642.9		1,517.6
lb/hr		1.26E+00		1.12E+00		1.04E+00
TPY		1.90E-01		1.68E-01		1.56E-01
Chlorine (lb/hr)= Basis (ppm) x Fuel oil (lb/hr) ÷ 1,000,000 (adj. for ppm)						
Basis, ppm		0.5		0.5		0.5
Fuel Oil (lb/hr)		99,722.9		88,568.4		81,812.7
lb/hr		4.99E-02		4.43E-02		4.09E-02
TPY		7.48E-03		6.64E-03		6.14E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Data		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		170,700.0	151,900.0	147,100.0	142,700.0	131,800.0
Heat Rate (Btu/kwh)		9,460.0	9,750.0	9,860.0	9,970.0	10,230.0
CT Exhaust Flow						
Mass Flow (lb/hr)		3,582,000	3,322,000	3,262,000	3,202,000	3,077,000
Temperature (oF)		1,078	1,110	1,117	1,124	1,140
Moisture (% Vol.)		7.61	8.83	9.21	10.05	9.91
Oxygen (% Vol.)		12.71	12.56	12.51	12.36	12.48
Molecular Weight		28.46	28.33	28.28	28.19	28.20
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		170,700.0	151,900.0	147,100.0	142,700.0	131,800.0
Heat Rate (Btu/kwh)		9,460.0	9,750.0	9,860.0	9,970.0	10,230.0
Heat Input (MMBtu/hr)		1,614.8	1,481.0	1,450.4	1,422.7	1,348.3
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)		1,614.8	1,481.0	1,450.4	1,422.7	1,348.3
Heat Content,LHV (Btu/lb)		21,515	21,515	21,515	21,515	21,515
Natural Gas (lb/hr)		75,055.6	68,836.9	67,413.7	66,126.8	62,668.6
Heat Content,LHV (Btu/cf)		950	950	950	950	950
Natural Gas (cf/hr)		1,699,813	1,558,974	1,526,743	1,497,599	1,419,278
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)		3,582,000	3,322,000	3,262,000	3,202,000	3,077,000
Temperature (°F)		1,078	1,110	1,117	1,124	1,140
Molecular Weight		28.46	28.33	28.28	28.19	28.20
Volume Flow (acfm)		2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
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)		3,582,000	3,322,000	3,262,000	3,202,000	3,077,000
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.46	28.33	28.28	28.19	28.20
Volume Flow (scfm)		808,255	753,259	740,784	729,581	700,802
HRSG Stack Data						
Stack Height (ft)		180	180	180	180	180
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
CT Temperature (°F)		1,078	1,110	1,117	1,124	1,140
HRSG Temperature (°F)		205	205	205	205	205
Volume Flow (acfm) from HRSG		1,017,973	948,707	932,995	918,885	882,639
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)^2÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		1,017,973	948,707	932,995	918,885	882,639
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)		66.7	62.1	61.1	60.2	57.8

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: General Electric, 1992.

Table A-7. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		9.0	9.0	9.0	9.0	9.0
lb/hr		9.0	9.0	9.0	9.0	9.0
TPY		38.07	38.07	38.07	38.07	38.07
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)		1,699,813	1,558,974	1,526,743	1,497,599	1,419,278
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
lb/hr		4.86	4.45	4.36	4.28	4.06
TPY		20.54	18.84	18.45	18.10	17.15
Nitrogen Oxides (lb/hr)= NOx(ppm) x ([20.9 x (1 - Moisture(%)/100)] - Oxygen(%)) x 2116.8 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* (1)		25.0	25.0	25.0	25.0	25.0
Moisture (%)		7.61	8.83	9.21	10.05	9.91
Oxygen (%)		12.71	12.56	12.51	12.36	12.48
Volume Flow (acfm)		2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
Temperature (°F)		1078	1110	1117	1124	1140
lb/hr		161.9	148.5	145.3	142.6	135.0
TPY		684.72	627.98	614.78	603.09	571.14
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+ (1)		15.0	15.0	15.0	15.0	15.0
Moisture (%)		7.61	8.83	9.21	10.05	9.91
Volume Flow (acfm)		2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
Temperature (°F)		1078	1110	1117	1124	1140
lb/hr		48.8	44.9	44.0	42.9	41.3
TPY		206.55	189.96	186.03	181.52	174.63
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		1.5	1.5	1.5	1.6	1.5
Moisture (%)		7.61	8.83	9.21	10.05	9.91
Volume Flow (acfm)		2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
Temperature (°F)		1078	1110	1117	1124	1140
lb/hr		2.79	2.57	2.51	2.62	2.36
TPY		11.80	10.85	10.63	11.06	9.98
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

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: General Electric, 1992.

Table A-8. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Arsenic (lb/hr)= Negligible						
Basis, 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
Beryllium (lb/hr)= Negligible						
Basis, 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
Mercury (lb/hr)= Negligible						
Basis, 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
Fluoride (lb/hr)= Negligible						
Basis, 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
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8	8	8	8	8
SO2 (lb/hr)		4.86	4.45	4.36	4.28	4.06
lb H2SO4/lb SO2 (98/64)		1.53	1.53	1.53	1.53	1.53
lb/hr		5.95E-01	5.46E-01	5.34E-01	5.24E-01	4.97E-01
TPY		2.52E+00	2.31E+00	2.26E+00	2.22E+00	2.10E+00

Source: (1) EPA, 1990

Table A-9. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Manganese (lb/hr)= Negligible						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (1)		1.113	1.113	1.113	1.113	1.113
HIR (MMBtu/hr)		1,614.8	1,481.0	1,450.4	1,422.7	1,348.3
lb/hr		1.80E-03	1.65E-03	1.61E-03	1.58E-03	1.50E-03
TPY		7.60E-03	6.97E-03	6.83E-03	6.70E-03	6.35E-03
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	88.12	88.12	88.12	88.12
HIR (MMBtu/hr)		1,614.8	1,481.0	1,450.4	1,422.7	1,348.3
lb/hr		1.42E-01	1.31E-01	1.28E-01	1.25E-01	1.19E-01
TPY		6.02E-01	5.52E-01	5.41E-01	5.30E-01	5.03E-01

Source: (1) EPA, 1990

Table A-10. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460		8460		8460
Antimony (lb/hr)= Negligible						
Basis, pg/J		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
Barium (lb/hr)= Negligible						
Basis, pg/J		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
Cobalt (lb/hr)= Negligible						
Basis, pg/J		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
Zinc (lb/hr)= Negligible						
Basis, pg/J		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
Chlorine (lb/hr)= Negligible						
Basis, ppm		NA	NA	NA	NA	NA
Natural gas (cf)		NA	NA	NA	NA	NA
lb/hr		NA	NA	NA	NA	NA
TPY		NA	NA	NA	NA	NA

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Table A-1A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Data		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		129,200.0		111,000.0		98,500.0
Heat Rate (Btu/kwh)		11,430.0		11,800.0		12,280.0
CT Exhaust Flow						
Mass Flow (lb/hr)		2,837,000		2,619,000		2,510,000
Temperature (oF)		1,166		1,192		1,200
Moisture (% Vol.)		11.96		12.40		12.48
Oxygen (% Vol.)		10.57		10.81		11.07
Molecular Weight		28.23		28.16		28.13
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		129,200.0		111,000.0		98,500.0
Heat Rate (Btu/kwh)		11,430.0		11,800.0		12,280.0
Heat Input (MMBtu/hr)		1,476.8		1,309.8		1,209.6
Fuel Oil Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)						
Heat Input (MMBtu/hr)		1,476.8		1,309.8		1,209.6
Heat Content,LHV (Btu/lb)		18,550		18,550		18,550
Fuel Oil (lb/hr)		79,609.5		70,609.2		65,206.5
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)		2,837,000		2,619,000		2,510,000
Temperature (°F)		1,166		1,192		1,200
Molecular Weight		28.23		28.16		28.13
Volume Flow (acfm)		1,988,010		1,869,045		1,802,083
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)		2,837,000		2,619,000		2,510,000
Temperature (°F)		68		68		68
Molecular Weight		28.23		28.16		28.13
Volume Flow (scfm)		645,553		597,370		573,193
HRSG Stack Data						
Stack Height (ft)		180		180		180
Diameter (ft)		18.0		18.0		18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		1,988,010		1,869,045		1,802,083
CT Temperature (°F)		1,166		1,192		1,200
HRSG Temperature (°F)		200		200		200
Volume Flow (acfm) from HRSG		806,941		746,713		716,491
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)^2÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		806,941		746,713		716,491
Diameter (ft)		18.0		18.0		18.0
Velocity (ft/sec)		52.9		48.9		46.9

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: General Electric, 1992.

Table A-2A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		17.0		17.0		17.0
lb/hr		17.0		17.0		17.0
TPY		2.6		2.6		2.6
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2/lb S) x fraction emitted as SO2						
Fuel Oil (lb/hr)		79,609.5		70,609.2		65,206.5
Sulfur content (%)		0.05		0.05		0.05
lb SO2/lb S (64/32)		2.0		2.0		2.0
SO2 Fraction emitted		1.00		1.00		1.00
lb/hr		79.61		70.61		65.21
TPY		11.9		10.6		9.8
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		42.0		42.0		42.0
Moisture (%)		11.96		12.4		12.48
Oxygen (%)		10.57		10.81		11.07
Volume Flow (acfm)		1,988,010		1,869,045		1,802,083
Temperature (°F)		1166		1192		1200
lb/hr		257.7		228.4		211.0
TPY		38.7		34.3		31.7
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+ (1)		30.0		30.0		30.0
Moisture (%)		11.96		12.4		12.48
Volume Flow (acfm)		1,988,010		1,869,045		1,802,083
Temperature (°F)		1166		1192		1200
lb/hr		74.3		68.4		65.6
TPY		11.1		10.3		9.8
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		4.0		4.0		4.1
Moisture (%)		11.96		12.4		12.48
Volume Flow (acfm)		1,988,010		1,869,045		1,802,083
Temperature (°F)		1166		1192		1200
lb/hr		5.66		5.21		5.12
TPY		0.8		0.8		0.8
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (2)		8.9		8.9		8.9
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		1.31E-02		1.17E-02		1.08E-02
TPY		1.97E-03		1.75E-03		1.61E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) General Electric, 1992; (2) EPA, 1990

Table A-3A. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Arsenic (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)		4.2		4.2		4.2
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		6.20E-03		5.50E-03		5.08E-03
TPY		9.30E-04		8.25E-04		7.62E-04
Beryllium (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)		2.5		2.5		2.5
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		3.69E-03		3.27E-03		3.02E-03
TPY		5.54E-04		4.91E-04		4.54E-04
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)		3		3		3
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		4.43E-03		3.93E-03		3.63E-03
TPY		6.65E-04		5.89E-04		5.44E-04
Fluoride (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (2)		14		14		14
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		4.80E-02		4.26E-02		3.94E-02
TPY		7.21E-03		6.39E-03		5.90E-03
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8		8		8
SO2 (lb/hr)		79.6		70.6		65.2
lb H2SO4/lb SO2 (98/64)		1.53		1.53		1.53
lb/hr		9.75E+00		8.65E+00		7.99E+00
TPY		1.46E+00		1.30E+00		1.20E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-4A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Manganese (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)		14		14		14
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		2.07E-02		1.83E-02		1.69E-02
TPY		3.10E-03		2.75E-03		2.54E-03
Nickel (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)		170		170		170
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		2.51E-01		2.23E-01		2.06E-01
TPY		3.77E-02		3.34E-02		3.08E-02
Cadmium (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)		10.5		10.5		10.5
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		1.55E-02		1.38E-02		1.27E-02
TPY		2.33E-03		2.06E-03		1.91E-03
Chromium (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)		47.5		47.5		47.5
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		7.01E-02		6.22E-02		5.75E-02
TPY		1.05E-02		9.33E-03		8.62E-03
Copper (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)		280		280		280
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		4.13E-01		3.67E-01		3.39E-01
TPY		6.20E-02		5.50E-02		5.08E-02
Vanadium (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)		69.5		69.5		69.5
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		1.03E-01		9.10E-02		8.41E-02
TPY		1.54E-02		1.37E-02		1.26E-02
Selenium (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)		23.42		23.42		23.42
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		3.46E-02		3.07E-02		2.83E-02
TPY		5.19E-03		4.60E-03		4.25E-03
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)		0.278		0.278		0.278
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		4.11E-04		3.64E-04		3.36E-04
TPY		6.16E-05		5.46E-05		5.04E-05
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)		405		405		405
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		5.98E-01		5.30E-01		4.90E-01
TPY		8.97E-02		7.96E-02		7.35E-02

Source: (1) EPA, 1990

Table A-5A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Antimony (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		9.4		9.4		9.4
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		3.23E-02		2.86E-02		2.64E-02
TPY		4.84E-03		4.29E-03		3.96E-03
Barium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		8.4		8.4		8.4
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		2.88E-02		2.56E-02		2.36E-02
TPY		4.32E-03		3.84E-03		3.54E-03
Cobalt (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		3.9		3.9		3.9
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		1.34E-02		1.19E-02		1.10E-02
TPY		2.01E-03		1.78E-03		1.64E-03
Zinc (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		294		294		294
HIR (MMBtu/hr)		1,476.8		1,309.8		1,209.6
lb/hr		1.01E+00		8.95E-01		8.26E-01
TPY		1.51E-01		1.34E-01		1.24E-01
Chlorine (lb/hr)= Basis (ppm) x Fuel oil (lb/hr) ÷ 1,000,000 (adj. for ppm)						
Basis, ppm		0.5		0.5		0.5
Fuel Oil (lb/hr)		79,609.5		70,609.2		65,206.5
lb/hr		3.98E-02		3.53E-02		3.26E-02
TPY		5.97E-03		5.30E-03		4.89E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Data		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		119,900.0	106,500.0	103,100.0	99,500.0	90,900.0
Heat Rate (Btu/kwh)		10,770.0	11,070.0	11,340.0	11,510.0	11,890.0
CT Exhaust Flow						
Mass Flow (lb/hr)		2,744,000	2,595,000	2,560,000	2,524,000	2,454,000
Temperature (oF)		1,177	1,195	1,199	1,200	1,200
Moisture (% Vol.)		7.84	8.98	9.34	10.14	9.89
Oxygen (% Vol.)		12.46	12.41	12.39	12.28	12.52
Molecular Weight		28.45	28.32	28.27	28.18	28.20
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		119,900.0	106,500.0	103,100.0	99,500.0	90,900.0
Heat Rate (Btu/kwh)		10,770.0	11,070.0	11,340.0	11,510.0	11,890.0
Heat Input (MMBtu/hr)		1,291.3	1,179.0	1,169.2	1,145.2	1,080.8
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)		1,291.3	1,179.0	1,169.2	1,145.2	1,080.8
Heat Content,LHV (Btu/lb)		21,515	21,515	21,515	21,515	21,515
Natural Gas (lb/hr)		60,019.7	54,796.9	54,341.3	53,230.1	50,234.8
Heat Content,LHV (Btu/cf)		950	950	950	950	950
Natural Gas (cf/hr)		1,359,287	1,241,005	1,230,688	1,205,521	1,137,685
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)		2,744,000	2,595,000	2,560,000	2,524,000	2,454,000
Temperature (°F)		1,177	1,195	1,199	1,200	1,200
Molecular Weight		28.45	28.32	28.27	28.18	28.20
Volume Flow (acfm)		1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
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)		2,744,000	2,595,000	2,560,000	2,524,000	2,454,000
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.45	28.32	28.27	28.18	28.20
Volume Flow (scfm)		619,500	588,641	581,580	575,224	558,903
HRSG Stack Data						
Stack Height (ft)		180	180	180	180	180
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
CT Temperature (°F)		1,177	1,195	1,199	1,200	1,200
HRSG Temperature (°F)		200	200	200	200	200
Volume Flow (acfm) from HRSG		774,375	735,801	726,975	719,030	698,629
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		774,375	735,801	726,975	719,030	698,629
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)		50.7	48.2	47.6	47.1	45.8

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft²

Source: General Electric, 1992.

Table A-7A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		9.0	9.0	9.0	9.0	9.0
lb/hr		9.0	9.0	9.0	9.0	9.0
TPY		38.07	38.07	38.07	38.07	38.07
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)		1,359,287	1,241,005	1,230,688	1,205,521	1,137,685
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
lb/hr		3.88	3.55	3.52	3.44	3.25
TPY		16.43	15.00	14.87	14.57	13.75
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		25.0	25.0	25.0	25.0	25.0
Moisture (%)		7.84	8.98	9.34	10.14	9.89
Oxygen (%)		12.46	12.41	12.39	12.28	12.52
Volume Flow (acfm)		1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
Temperature (°F)		1177	1195	1199	1200	1200
lb/hr		127.9	118.1	115.7	113.5	107.1
TPY		540.88	499.71	489.59	480.01	452.93
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+ (1)		15.0	15.0	15.0	15.0	15.0
Moisture (%)		7.84	8.98	9.34	10.14	9.89
Volume Flow (acfm)		1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
Temperature (°F)		1177	1195	1199	1200	1200
lb/hr		37.3	35.0	34.5	33.8	32.9
TPY		157.92	148.20	145.84	142.98	139.31
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		1.5	1.5	1.5	1.6	1.5
Moisture (%)		7.84	8.98	9.34	10.14	9.89
Volume Flow (acfm)		1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
Temperature (°F)		1177	1195	1199	1200	1200
lb/hr		2.13	2.00	2.00	2.06	1.88
TPY		9.02	8.47	8.44	8.71	7.96
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

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: General Electric, 1992.

Table A-8A. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Arsenic (lb/hr)= Negligible						
Basis, 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
Beryllium (lb/hr)= Negligible						
Basis, 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
Mercury (lb/hr)= Negligible						
Basis, 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
Fluoride (lb/hr)= Negligible						
Basis, 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
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8	8	8	8	8
SO2 (lb/hr)		3.88	3.55	3.52	3.44	3.25
lb H2SO4/lb SO2 (98/64)		1.53	1.53	1.53	1.53	1.53
lb/hr		4.76E-01	4.34E-01	4.31E-01	4.22E-01	3.98E-01
TPY		2.01E+00	1.84E+00	1.82E+00	1.78E+00	1.68E+00

Source: (1) EPA, 1990

Table A-9A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Manganese (lb/hr)= Negligible						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (1)		1.113	1.113	1.113	1.113	1.113
HIR (MMBtu/hr)		1,291.3	1,179.0	1,169.2	1,145.2	1,080.8
lb/hr		1.44E-03	1.31E-03	1.30E-03	1.27E-03	1.20E-03
TPY		6.08E-03	5.55E-03	5.50E-03	5.39E-03	5.09E-03
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	88.12	88.12	88.12	88.12
HIR (MMBtu/hr)		1,291.3	1,179.0	1,169.2	1,145.2	1,080.8
lb/hr		1.14E-01	1.04E-01	1.03E-01	1.01E-01	9.52E-02
TPY		4.81E-01	4.39E-01	4.36E-01	4.27E-01	4.03E-01

Source: (1) EPA, 1990

Table A-10A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460		8460		8460
Antimony (lb/hr)= Negligible						
Basis, pg/J		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
Barium (lb/hr)= Negligible						
Basis, pg/J		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
Cobalt (lb/hr)= Negligible						
Basis, pg/J		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
Zinc (lb/hr)= Negligible						
Basis, pg/J		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
Chlorine (lb/hr)= Negligible						
Basis, ppm		NA	NA	NA	NA	NA
Natural gas (cf)		NA	NA	NA	NA	NA
lb/hr		NA	NA	NA	NA	NA
TPY		NA	NA	NA	NA	NA

Table A-19. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Data		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		171,970.0		162,330.0		147,180.0
Heat Rate (Btu/kwh)		9,280.0		9,560.0		9,850.0
CT Exhaust Flow						
Mass Flow (lb/hr)		3,502,180		3,509,380		3,311,800
Temperature (oF)		1,104		1,104		1,121
Moisture (% Vol.)		10.60		11.91		12.57
Oxygen (% Vol.)		11.92		11.88		11.83
Molecular Weight		28.33		28.17		28.09
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		171,970.0		162,330.0		147,180.0
Heat Rate (Btu/kwh)		9,280.0		9,560.0		9,850.0
Heat Input (MMBtu/hr)		1,595.9		1,551.9		1,449.7
Fuel Oil Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)						
Heat Input (MMBtu/hr)		1,595.9		1,551.9		1,449.7
Heat Content,LHV (Btu/lb)		18,450		18,450		18,450
Fuel Oil (lb/hr)		86,497.6		84,112.5		78,575.8
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)		3,502,180		3,509,380		3,311,800
Temperature (°F)		1,104		1,104		1,121
Molecular Weight		28.33		28.17		28.09
Volume Flow (acfm)		2,351,909		2,370,209		2,267,804
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)		3,502,180		3,509,380		3,311,800
Temperature (°F)		68		68		68
Molecular Weight		28.33		28.17		28.09
Volume Flow (scfm)		793,995		800,173		757,369
HRSG Stack Data						
Stack Height (ft)		180		180		180
Diameter (ft)		18.0		18.0		18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		2,351,909		2,370,209		2,267,804
CT Temperature (°F)		1,104		1,104		1,121
HRSG Temperature (°F)		205		205		205
Volume Flow (acfm) from HRSG		1,000,012		1,007,794		953,883
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		1,000,012		1,007,794		953,883
Diameter (ft)		18.0		18.0		18.0
Velocity (ft/sec)		65.5		66.0		62.5

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft²

Source: Westinghouse, 1992.

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Table A-20. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		39.5		39.0		36.7
lb/hr		39.5		39.0		36.7
TPY		5.9		5.9		5.5
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2/lb S) x fraction emitted as SO2						
Fuel Oil (lb/hr)		86,497.6		84,112.5		78,575.8
Sulfur content (%)		0.05		0.05		0.05
lb SO2/lb S (64/32)		2.0		2.0		2.0
SO2 Fraction emitted		1.00		1.00		1.00
lb/hr		89.35		86.22		81.33
TPY		13.4		12.9		12.2
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		44.5		42.7		42.7
Moisture (%)		10.6		11.91		12.57
Oxygen (%)		11.92		11.88		11.83
Volume Flow (acfm)		2,351,909		2,370,209		2,267,804
Temperature (°F)		1104		1104		1121
lb/hr		290.1		270.9		252.9
TPY		43.5		40.6		37.9
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+ (1)		52.0		51.6		51.5
Moisture (%)		10.6		11.91		12.57
Volume Flow (acfm)		2,351,909		2,370,209		2,267,804
Temperature (°F)		1104		1104		1121
lb/hr		160.9		158.4		148.7
TPY		24.1		23.8		22.3
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		10.6		10.5		10.5
Moisture (%)		10.6		11.91		12.57
Volume Flow (acfm)		2,351,909		2,370,209		2,267,804
Temperature (°F)		1104		1104		1121
lb/hr		18.74		18.44		17.32
TPY		2.8		2.8		2.6
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (2)		8.9		8.9		8.9
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		1.42E-02		1.38E-02		1.29E-02
TPY		2.13E-03		2.07E-03		1.94E-03

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: (1) Westinghouse, 1992; (2) EPA, 1990

Table A-21. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility
Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Arsenic (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)		4.2		4.2		4.2
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		6.70E-03		6.52E-03		6.09E-03
TPY		1.01E-03		9.78E-04		9.13E-04
Beryllium (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)		2.5		2.5		2.5
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		3.99E-03		3.88E-03		3.62E-03
TPY		5.98E-04		5.82E-04		5.44E-04
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)		3		3		3
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		4.79E-03		4.66E-03		4.35E-03
TPY		7.18E-04		6.98E-04		6.52E-04
Fluoride (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (2)		14		14		14
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		5.19E-02		5.05E-02		4.72E-02
TPY		7.79E-03		7.57E-03		7.08E-03
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8		8		8
SO2 (lb/hr)		89.4		86.2		81.3
lb H2SO4/lb SO2 (98/64)		1.53		1.53		1.53
lb/hr		1.09E+01		1.06E+01		9.96E+00
TPY		1.64E+00		1.58E+00		1.49E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-22. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Manganese (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)		14		14		14
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		2.23E-02		2.17E-02		2.03E-02
TPY		3.35E-03		3.26E-03		3.04E-03
Nickel (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)		170		170		170
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		2.71E-01		2.64E-01		2.46E-01
TPY		4.07E-02		3.96E-02		3.70E-02
Cadmium (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)		10.5		10.5		10.5
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		1.68E-02		1.63E-02		1.52E-02
TPY		2.51E-03		2.44E-03		2.28E-03
Chromium (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)		47.5		47.5		47.5
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		7.58E-02		7.37E-02		6.89E-02
TPY		1.14E-02		1.11E-02		1.03E-02
Copper (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)		280		280		280
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		4.47E-01		4.35E-01		4.06E-01
TPY		6.70E-02		6.52E-02		6.09E-02
Vanadium (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)		69.5		69.5		69.5
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		1.11E-01		1.08E-01		1.01E-01
TPY		1.66E-02		1.62E-02		1.51E-02
Selenium (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)		23.42		23.42		23.42
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		3.74E-02		3.63E-02		3.40E-02
TPY		5.61E-03		5.45E-03		5.09E-03
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)		0.278		0.278		0.278
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		4.44E-04		4.31E-04		4.03E-04
TPY		6.65E-05		6.47E-05		6.05E-05
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)		405		405		405
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		6.46E-01		6.29E-01		5.87E-01
TPY		9.69E-02		9.43E-02		8.81E-02

Source: (1) EPA, 1990

Table A-23. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Antimony (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		9.4		9.4		9.4
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		3.49E-02		3.39E-02		3.17E-02
TPY		5.23E-03		5.09E-03		4.75E-03
Barium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		8.4		8.4		8.4
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		3.12E-02		3.03E-02		2.83E-02
TPY		4.67E-03		4.54E-03		4.25E-03
Cobalt (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		3.9		3.9		3.9
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		1.45E-02		1.41E-02		1.31E-02
TPY		2.17E-03		2.11E-03		1.97E-03
Zinc (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		294		294		294
HIR (MMBtu/hr)		1,595.9		1,551.9		1,449.7
lb/hr		1.09E+00		1.06E+00		9.91E-01
TPY		1.64E-01		1.59E-01		1.49E-01
Chlorine (lb/hr)= Basis (ppm) x Fuel oil (lb/hr) ÷ 1,000,000 (adj. for ppm)						
Basis, ppm		0.5		0.5		0.5
Fuel Oil (lb/hr)		86,497.6		84,112.5		78,575.8
lb/hr		4.32E-02		4.21E-02		3.93E-02
TPY		6.49E-03		6.31E-03		5.89E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Table A-24. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Data		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		169,210.0	147,950.0	143,450.0	139,500.0	129,370.0
Heat Rate (Btu/kwh)		9,490.0	9,900.0	10,000.0	10,100.0	10,360.0
CT Exhaust Flow						
Mass Flow (lb/hr)		3,702,540	3,431,310	3,369,010	3,311,770	3,180,510
Temperature (oF)		1,063	1,086	1,092	1,098	1,111
Moisture (% Vol.)		7.26	8.45	8.82	9.32	9.56
Oxygen (% Vol.)		13.08	12.97	12.91	12.82	12.84
Molecular Weight		28.49	28.36	28.32	28.26	28.23
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		169,210.0	147,950.0	143,450.0	139,500.0	129,370.0
Heat Rate (Btu/kwh)		9,490.0	9,900.0	10,000.0	10,100.0	10,360.0
Heat Input (MMBtu/hr)		1,605.8	1,464.7	1,434.5	1,409.0	1,340.3
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)		1,605.8	1,464.7	1,434.5	1,409.0	1,340.3
Heat Content,LHV (Btu/lb)		20,900	20,900	20,900	20,900	20,900
Natural Gas (lb/hr)		76,832.7	70,081.6	68,636.4	67,413.9	64,127.9
Heat Content,LHV (Btu/cf)		950	950	950	950	950
Natural Gas (cf/hr)		1,690,319	1,541,795	1,510,000	1,483,105	1,410,814
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)		3,702,540	3,431,310	3,369,010	3,311,770	3,180,510
Temperature (°F)		1,063	1,086	1,092	1,098	1,111
Molecular Weight		28.49	28.36	28.32	28.26	28.23
Volume Flow (acfm)		2,407,465	2,275,544	2,246,146	2,221,160	2,152,966
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)		3,702,540	3,431,310	3,369,010	3,311,770	3,180,510
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.49	28.36	28.32	28.26	28.23
Volume Flow (scfm)		834,630	777,159	764,153	752,742	723,594
HRSG Stack Data						
Stack Height (ft)		180	180	180	180	180
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		2,407,465	2,275,544	2,246,146	2,221,160	2,152,966
CT Temperature (°F)		1,063	1,086	1,092	1,098	1,111
HRSG Temperature (°F)		205	205	205	205	205
Volume Flow (acfm) from HRSG		1,051,191	978,808	962,427	948,056	911,345
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)^2÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		1,051,191	978,808	962,427	948,056	911,345
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)		68.8	64.1	63.0	62.1	59.7

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: Westinghouse, 1992.

Table A-25. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		6.60	6.10	6.00	5.90	5.70
lb/hr		6.60	6.10	6.00	5.90	5.70
TPY		27.92	25.80	25.38	24.96	24.11
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)		1,690,319	1,541,795	1,510,000	1,483,105	1,410,814
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
lb/hr		4.83	4.41	4.31	4.24	4.03
TPY		20.43	18.63	18.25	17.92	17.05
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		25.5	25.5	25.4	25.5	25.5
Moisture (%)		7.26	8.45	8.82	9.32	9.56
Oxygen (%)		13.08	12.97	12.91	12.82	12.84
Volume Flow (acfm)		2,407,465	2,275,544	2,246,146	2,221,160	2,152,966
Temperature (°F)		1063	1086	1092	1098	1111
lb/hr		162.8	148.3	144.8	142.9	135.8
TPY		688.77	627.23	612.58	604.38	574.33
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+ (1)		10.3	10.4	10.3	10.4	10.2
Moisture (%)		7.26	8.45	8.82	9.32	9.56
Volume Flow (acfm)		2,407,465	2,275,544	2,246,146	2,221,160	2,152,966
Temperature (°F)		1063	1086	1092	1098	1111
lb/hr		34.8	32.3	31.3	30.9	29.1
TPY		147.02	136.45	132.34	130.91	123.09
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		4.2	4.0	4.1	4.1	4.3
Moisture (%)		7.26	8.45	8.82	9.32	9.56
Volume Flow (acfm)		2,407,465	2,275,544	2,246,146	2,221,160	2,152,966
Temperature (°F)		1063	1086	1092	1098	1111
lb/hr		8.10	7.09	7.12	6.97	7.01
TPY		34.26	29.99	30.10	29.49	29.65
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

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: Westinghouse, 1992.

Table A-26. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Arsenic (lb/hr)= Negligible						
Basis, 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
Beryllium (lb/hr)= Negligible						
Basis, 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
Mercury (lb/hr)= Negligible						
Basis, 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
Fluoride (lb/hr)= Negligible						
Basis, 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
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8	8	8	8	8
SO2 (lb/hr)		4.83	4.41	4.31	4.24	4.03
lb H2SO4/lb SO2 (98/64)		1.53	1.53	1.53	1.53	1.53
lb/hr		6.23E-01	5.68E-01	5.56E-01	5.46E-01	5.20E-01
TPY		2.63E+00	2.40E+00	2.35E+00	2.31E+00	2.20E+00

Source: (1) EPA, 1990

Table A-27. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Manganese (lb/hr)= Negligible						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (1)		1.113	1.113	1.113	1.113	1.113
HIR (MMBtu/hr)		1,605.8	1,464.7	1,434.5	1,409.0	1,340.3
lb/hr		1.79E-03	1.63E-03	1.60E-03	1.57E-03	1.49E-03
TPY		7.56E-03	6.90E-03	6.75E-03	6.63E-03	6.31E-03
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	88.12	88.12	88.12	88.12
HIR (MMBtu/hr)		1,605.8	1,464.7	1,434.5	1,409.0	1,340.3
lb/hr		1.42E-01	1.29E-01	1.26E-01	1.24E-01	1.18E-01
TPY		5.99E-01	5.46E-01	5.35E-01	5.25E-01	5.00E-01

Source: (1) EPA, 1990

Table A-28. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460		8460		8460
Antimony (lb/hr)= Negligible						
Basis, pg/J		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
Barium (lb/hr)= Negligible						
Basis, pg/J		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
Cobalt (lb/hr)= Negligible						
Basis, pg/J		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
Zinc (lb/hr)= Negligible						
Basis, pg/J		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
Chlorine (lb/hr)= Negligible						
Basis, ppm		NA	NA	NA	NA	NA
Natural gas (cf)		NA	NA	NA	NA	NA
lb/hr		NA	NA	NA	NA	NA
TPY		NA	NA	NA	NA	NA

Table A-19A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Data		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		133,020.0		113,400.0		102,810.0
Heat Rate (Btu/kwh)		9,770.0		10,310.0		10,680.0
CT Exhaust Flow						
Mass Flow (lb/hr)		2,934,960		2,757,580		2,662,180
Temperature (oF)		1,130		1,130		1,130
Moisture (% Vol.)		10.43		11.58		12.09
Oxygen (% Vol.)		12.08		12.17		12.26
Molecular Weight		28.34		28.19		28.12
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		133,020.0		113,400.0		102,810.0
Heat Rate (Btu/kwh)		9,770.0		10,310.0		10,680.0
Heat Input (MMBtu/hr)		1,299.6		1,169.2		1,098.0
Fuel Oil Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)						
Heat Input (MMBtu/hr)		1,299.6		1,169.2		1,098.0
Heat Content,LHV (Btu/lb)		18,450		18,450		18,450
Fuel Oil (lb/hr)		70,439.3		63,368.8		59,512.8
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)		2,934,960		2,757,580		2,662,180
Temperature (°F)		1,130		1,130		1,130
Molecular Weight		28.34		28.19		28.12
Volume Flow (acfm)		2,003,120		1,892,217		1,831,107
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)		2,934,960		2,757,580		2,662,180
Temperature (°F)		68		68		68
Molecular Weight		28.34		28.19		28.12
Volume Flow (scfm)		665,187		628,359		608,066
HRSG Stack Data						
Stack Height (ft)		180		180		180
Diameter (ft)		18.0		18.0		18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		2,003,120		1,892,217		1,831,107
CT Temperature (°F)		1,130		1,130		1,130
HRSG Temperature (°F)		200		200		200
Volume Flow (acfm) from HRSG		831,484		785,449		760,082
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)^2÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		831,484		785,449		760,082
Diameter (ft)		18.0		18.0		18.0
Velocity (ft/sec)		54.5		51.4		49.8

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Source: Westinghouse, 1992.

Table A-20A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		32.6		30.0		28.5
lb/hr		32.6		30.0		28.5
TPY		4.9		4.5		4.3
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2/lb S) x fraction emitted as SO2						
Fuel Oil (lb/hr)		70,439.3		63,368.8		59,512.8
Sulfur content (%)		0.05		0.05		0.05
lb SO2/lb S (64/32)		2.0		2.0		2.0
SO2 Fraction emitted		1.00		1.00		1.00
lb/hr		72.69		65.65		61.77
TPY		10.9		9.8		9.3
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		42.5		42.5		42.7
Moisture (%)		10.43		11.58		12.09
Oxygen (%)		12.08		12.17		12.26
Volume Flow (acfm)		2,003,120		1,892,217		1,831,107
Temperature (°F)		1130		1130		1130
lb/hr		227.9		204.5		192.7
TPY		34.2		30.7		28.9
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+ (1)		51.5		51.5		51.5
Moisture (%)		10.43		11.58		12.09
Volume Flow (acfm)		2,003,120		1,892,217		1,831,107
Temperature (°F)		1130		1130		1130
lb/hr		133.8		124.7		120.0
TPY		20.1		18.7		18.0
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		10.0		10.1		10.5
Moisture (%)		10.43		11.58		12.09
Volume Flow (acfm)		2,003,120		1,892,217		1,831,107
Temperature (°F)		1130		1130		1130
lb/hr		14.84		13.98		13.98
TPY		2.2		2.1		2.1
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (2)		8.9		8.9		8.9
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		1.16E-02		1.04E-02		9.77E-03
TPY		1.73E-03		1.56E-03		1.47E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) Westinghouse, 1992; (2) EPA, 1990

Table A-21A. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility
Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Arsenic (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)		4.2		4.2		4.2
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		5.46E-03		4.91E-03		4.61E-03
TPY		8.19E-04		7.37E-04		6.92E-04
Beryllium (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)		2.5		2.5		2.5
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		3.25E-03		2.92E-03		2.75E-03
TPY		4.87E-04		4.38E-04		4.12E-04
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)		3		3		3
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		3.90E-03		3.51E-03		3.29E-03
TPY		5.85E-04		5.26E-04		4.94E-04
Fluoride (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (2)		14		14		14
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		4.23E-02		3.80E-02		3.57E-02
TPY		6.34E-03		5.71E-03		5.36E-03
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8		8		8
SO2 (lb/hr)		72.7		65.7		61.8
lb H2SO4/lb SO2 (98/64)		1.53		1.53		1.53
lb/hr		8.90E+00		8.04E+00		7.57E+00
TPY		1.34E+00		1.21E+00		1.14E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-22A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Manganese (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)		14		14		14
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		1.82E-02		1.64E-02		1.54E-02
TPY		2.73E-03		2.46E-03		2.31E-03
Nickel (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)		170		170		170
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		2.21E-01		1.99E-01		1.87E-01
TPY		3.31E-02		2.98E-02		2.80E-02
Cadmium (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)		10.5		10.5		10.5
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		1.36E-02		1.23E-02		1.15E-02
TPY		2.05E-03		1.84E-03		1.73E-03
Chromium (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)		47.5		47.5		47.5
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		6.17E-02		5.55E-02		5.22E-02
TPY		9.26E-03		8.33E-03		7.82E-03
Copper (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)		280		280		280
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		3.64E-01		3.27E-01		3.07E-01
TPY		5.46E-02		4.91E-02		4.61E-02
Vanadium (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)		69.5		69.5		69.5
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		9.03E-02		8.13E-02		7.63E-02
TPY		1.35E-02		1.22E-02		1.14E-02
Selenium (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)		23.42		23.42		23.42
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		3.04E-02		2.74E-02		2.57E-02
TPY		4.57E-03		4.11E-03		3.86E-03
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)		0.278		0.278		0.278
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		3.61E-04		3.25E-04		3.05E-04
TPY		5.42E-05		4.88E-05		4.58E-05
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)		405		405		405
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		5.26E-01		4.74E-01		4.45E-01
TPY		7.90E-02		7.10E-02		6.67E-02

Source: (1) EPA, 1990

Table A-23A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27 °F	* Not Available * Gas Turbine Fuel Oil 64 °F	Gas Turbine Fuel Oil 72 °F	* Not Available * Gas Turbine Fuel Oil 79 °F	Gas Turbine Fuel Oil 97 °F
A	B	C	D	E	F	G
Hours of Operation		300		300		300
Antimony (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		9.4		9.4		9.4
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		2.84E-02		2.55E-02		2.40E-02
TPY		4.26E-03		3.83E-03		3.60E-03
Barium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		8.4		8.4		8.4
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		2.54E-02		2.28E-02		2.14E-02
TPY		3.81E-03		3.42E-03		3.22E-03
Cobalt (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		3.9		3.9		3.9
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		1.18E-02		1.06E-02		9.95E-03
TPY		1.77E-03		1.59E-03		1.49E-03
Zinc (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 MMBtu/10E+12 Btu						
Basis, pg/J (1)		294		294		294
HIR (MMBtu/hr)		1,299.6		1,169.2		1,098.0
lb/hr		8.88E-01		7.99E-01		7.50E-01
TPY		1.33E-01		1.20E-01		1.13E-01
Chlorine (lb/hr)= Basis (ppm) x Fuel oil (lb/hr) ÷ 1,000,000 (adj. for ppm)						
Basis, ppm		0.5		0.5		0.5
Fuel Oil (lb/hr)		70,439.3		63,368.8		59,512.8
lb/hr		3.52E-02		3.17E-02		2.98E-02
TPY		5.28E-03		4.75E-03		4.46E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-24A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Data		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		118,330.0	103,390.0	100,210.0	97,490.0	90,340.0
Heat Rate (Btu/kwh)		10,490.0	11,020.0	11,150.0	11,270.0	11,600.0
CT Exhaust Flow						
Mass Flow (lb/hr)		2,754,000	2,678,720	2,647,790	2,619,850	2,554,960
Temperature (oF)		1,130	1,130	1,130	1,130	1,130
Moisture (% Vol.)		7.30	8.32	8.68	9.12	9.29
Oxygen (% Vol.)		13.04	13.10	13.08	13.04	13.15
Molecular Weight		28.49	28.36	28.33	28.27	28.25
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		118,330.0	103,390.0	100,210.0	97,490.0	90,340.0
Heat Rate (Btu/kwh)		10,490.0	11,020.0	11,150.0	11,270.0	11,600.0
Heat Input (MMBtu/hr)		1,241.3	1,139.4	1,117.3	1,098.7	1,047.9
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)		1,241.3	1,139.4	1,117.3	1,098.7	1,047.9
Heat Content,LHV (Btu/lb)		20,900	20,900	20,900	20,900	20,900
Natural Gas (lb/hr)		59,391.5	54,514.7	53,461.3	52,570.0	50,140.9
Heat Content,LHV (Btu/cf)		950	950	950	950	950
Natural Gas (cf/hr)		1,306,612	1,199,324	1,176,149	1,156,539	1,103,099
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)		2,754,000	2,678,720	2,647,790	2,619,850	2,554,960
Temperature (°F)		1,130	1,130	1,130	1,130	1,130
Molecular Weight		28.49	28.36	28.33	28.27	28.25
Volume Flow (acfm)		1,869,744	1,826,635	1,807,837	1,792,201	1,749,383
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)		2,754,000	2,678,720	2,647,790	2,619,850	2,554,960
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.49	28.36	28.33	28.27	28.25
Volume Flow (scfm)		620,896	606,581	600,338	595,146	580,927
HRSG Stack Data						
Stack Height (ft)		180	180	180	180	180
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		1,869,744	1,826,635	1,807,837	1,792,201	1,749,383
CT Temperature (°F)		1,130	1,130	1,130	1,130	1,130
HRSG Temperature (°F)		200	200	200	200	200
Volume Flow (acfm) from HRSG		776,120	758,226	750,423	743,932	726,159
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)² ÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		776,120	758,226	750,423	743,932	726,159
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)		50.8	49.7	49.1	48.7	47.6

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft²

Source: Westinghouse, 1992.

Table A-25A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
Basis, lb/hr (manufactur.) (1)		4.90	4.80	4.70	4.70	4.60
lb/hr		4.90	4.80	4.70	4.70	4.60
TPY		20.73	20.30	19.88	19.88	19.46
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)		1,306,612	1,199,324	1,176,149	1,156,539	1,103,099
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
lb/hr		3.73	3.43	3.36	3.30	3.15
TPY		15.79	14.49	14.21	13.98	13.33
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 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* (1)		25.4	25.4	25.4	25.4	25.4
Moisture (%)		7.3	8.32	8.68	9.12	9.29
Oxygen (%)		13.04	13.1	13.08	13.04	13.15
Volume Flow (acfm)		1,869,744	1,826,635	1,807,837	1,792,201	1,749,383
Temperature (°F)		1130	1130	1130	1130	1130
lb/hr		121.3	113.4	111.2	109.3	104.0
TPY		512.94	479.50	470.24	462.14	440.07
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+ (1)		10.4	10.3	10.4	10.2	10.4
Moisture (%)		7.3	8.32	8.68	9.12	9.29
Volume Flow (acfm)		1,869,744	1,826,635	1,807,837	1,792,201	1,749,383
Temperature (°F)		1130	1130	1130	1130	1130
lb/hr		26.1	25.0	24.9	24.1	23.9
TPY		110.38	105.63	105.44	101.73	101.06
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+ (1)		4.2	4.3	4.4	4.5	3.8
Moisture (%)		7.3	8.32	8.68	9.12	9.29
Volume Flow (acfm)		1,869,744	1,826,635	1,807,837	1,792,201	1,749,383
Temperature (°F)		1130	1130	1130	1130	1130
lb/hr		6.02	5.96	6.01	6.06	4.99
TPY		25.47	25.20	25.42	25.65	21.10
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

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: Westinghouse, 1992.

Table A-26A. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Arsenic (lb/hr)= Negligible						
Basis, 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
Beryllium (lb/hr)= Negligible						
Basis, 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
Mercury (lb/hr)= Negligible						
Basis, 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
Fluoride (lb/hr)= Negligible						
Basis, 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
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8	8	8	8	8
SO2 (lb/hr)		3.73	3.43	3.36	3.30	3.15
lb H2SO4/lb SO2 (98/64)		1.53	1.53	1.53	1.53	1.53
lb/hr		4.81E-01	4.42E-01	4.33E-01	4.26E-01	4.06E-01
TPY		2.04E+00	1.87E+00	1.83E+00	1.80E+00	1.72E+00

Source: (1) EPA, 1990

Table A-27A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460	8460	8460	8460	8460
Manganese (lb/hr)= Negligible						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (1)		1.113	1.113	1.113	1.113	1.113
HIR (MMBtu/hr)		1,241.3	1,139.4	1,117.3	1,098.7	1,047.9
lb/hr		1.38E-03	1.27E-03	1.24E-03	1.22E-03	1.17E-03
TPY		5.84E-03	5.36E-03	5.26E-03	5.17E-03	4.93E-03
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	88.12	88.12	88.12	88.12
HIR (MMBtu/hr)		1,241.3	1,139.4	1,117.3	1,098.7	1,047.9
lb/hr		1.09E-01	1.00E-01	9.85E-02	9.68E-02	9.23E-02
TPY		4.63E-01	4.25E-01	4.16E-01	4.10E-01	3.91E-01

Source: (1) EPA, 1990

Table A-28A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27 °F	Gas Turbine Natural Gas 64 °F	Gas Turbine Natural Gas 72 °F	Gas Turbine Natural Gas 79 °F	Gas Turbine Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8460		8460		8460
Antimony (lb/hr)= Negligible						
Basis, pg/J		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
Barium (lb/hr)= Negligible						
Basis, pg/J		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
Cobalt (lb/hr)= Negligible						
Basis, pg/J		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
Zinc (lb/hr)= Negligible						
Basis, pg/J		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
Chlorine (lb/hr)= Negligible						
Basis, ppm		NA	NA	NA	NA	NA
Natural gas (cf)		NA	NA	NA	NA	NA
lb/hr		NA	NA	NA	NA	NA
TPY		NA	NA	NA	NA	NA

Table A-11. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data		Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)		NA	NA	NA	NA	NA
DB Exhaust Flow						
Mass Flow (lb/hr)		5,244	5,244	5,244	5,244	5,244
Temperature (oF)		205	205	205	205	205
Moisture (% Vol.)		NA	NA	NA	NA	NA
Oxygen (% Vol.)		NA	NA	NA	NA	NA
Molecular Weight		28.00	28.00	28.00	28.00	28.00
Heat Input (MMBtu/hr)= As given						
Power (kW)		NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)		NA	NA	NA	NA	NA
Heat Input (MMBtu/hr)		100.0	100.0	100.0	100.0	100.0
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)		100.0	100.0	100.0	100.0	100.0
Heat Content,LHV (Btu/lb)		23,839	23,839	23,839	23,839	23,839
Natural Gas (lb/hr)		4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
Heat Content,LHV (Btu/cf)		950	950	950	950	950
Natural Gas (cf/hr)		105,263	105,263	105,263	105,263	105,263
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)		5,244	5,244	5,244	5,244	5,244
Temperature (°F)		205	205	205	205	205
Molecular Weight		28.00	28.00	28.00	28.00	28.00
Volume Flow (acfm)		1,515	1,515	1,515	1,515	1,515
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)		5,244	5,244	5,244	5,244	5,244
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.00	28.00	28.00	28.00	28.00
Volume Flow (scfm)		1,203	1,203	1,203	1,203	1,203
HRSG Stack Data						
Stack Height (ft)		180	180	180	180	180
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Volume Flow (acfm) from DB= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from DB		1,515	1,515	1,515	1,515	1,515
Assumed DB Exhaust Temp.(°F)		205	205	205	205	205
HRSG Temperature (°F)		205	205	205	205	205
Volume Flow (acfm) from DB		1,515	1,515	1,515	1,515	1,515
Velocity (ft/sec)= Volume flow (acfm) from DB ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from DB		1,515	1,515	1,515	1,515	1,515
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)		0.1	0.1	0.1	0.1	0.1

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft²

Source: Destec Engineering, Inc., 1992

Table A-12. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant		Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8760	8760	8760	8760	8760
Particulate (lb/hr)= Basis (lb/MMBtu) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.01	0.01	0.01	0.01	0.01
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		1.00	1.00	1.00	1.00	1.00
TPY		4.38	4.38	4.38	4.38	4.38
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)		105,263	105,263	105,263	105,263	105,263
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
lb/hr		0.30	0.30	0.30	0.30	0.30
TPY		1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides (lb/hr)= Basis (lb/MMBtu/hr) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.10	0.10	0.10	0.10	0.10
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		10.00	10.00	10.00	10.00	10.00
TPY		43.80	43.80	43.80	43.80	43.80
Carbon Monoxide (lb/hr)= Basis (lb/MMBtu) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.10	0.10	0.10	0.10	0.10
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		10.00	10.00	10.00	10.00	10.00
TPY		43.80	43.80	43.80	43.80	43.80
VOCs (lb/hr)= Basis (lb/MMBtu) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.029	0.029	0.029	0.029	0.029
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		2.90	2.90	2.90	2.90	2.90
TPY		12.70	12.70	12.70	12.70	12.70
Lead (lb/hr)= Negligible						
Basis, lb/MMBtu		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

Table A-13. Maximum Emissions of Other Regulated Pollutants for DESTEC Central Florida Cogeneration Facility Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8760	8760	8760	8760	8760
Arsenic (lb/hr)= Negligible						
Basis, 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
Beryllium (lb/hr)= Negligible						
Basis, 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
Mercury (lb/hr)= Negligible						
Basis, 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
Fluoride (lb/hr)= Negligible						
Basis, 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
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8	8	8	8	8
SO2 (lb/hr)		0.30	0.30	0.30	0.30	0.30
lb H2SO4/lb SO2 (98/64)		1.53	1.53	1.53	1.53	1.53
lb/hr		3.68E-02	3.68E-02	3.68E-02	3.68E-02	3.68E-02
TPY		1.61E-01	1.61E-01	1.61E-01	1.61E-01	1.61E-01

Source: EPA, 1990

Table A-14. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8760	8760	8760	8760	8760
Manganese (lb/hr)= Negligible						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (1)		1.113	1.113	1.113	1.113	1.113
HIR (MMBtu/hr)		100.0	100.0	100.0	100.0	100.0
lb/hr		1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
TPY		4.87E-04	4.87E-04	4.87E-04	4.87E-04	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	88.12	88.12	88.12	88.12
HIR (MMBtu/hr)		100.0	100.0	100.0	100.0	100.0
lb/hr		8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
TPY		3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02

Source: (1) EPA, 1990

Table A-11A. Design Information for DESTEC Central Florida Cogeneration Facility- Duct Burner, Supplemental Firing, Natural Gas

Data		Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
General						
Power (kW)		NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)		NA	NA	NA	NA	NA
DB Exhaust Flow						
Mass Flow (lb/hr)		5,244	5,244	5,244	5,244	5,244
Temperature (oF)		200	200	200	200	200
Moisture (% Vol.)		NA	NA	NA	NA	NA
Oxygen (% Vol.)		NA	NA	NA	NA	NA
Molecular Weight		28.00	28.00	28.00	28.00	28.00
Heat Input (MMBtu/hr)= As given						
Power (kW)		NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)		NA	NA	NA	NA	NA
Heat Input (MMBtu/hr)		100.0	100.0	100.0	100.0	100.0
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)		100.0	100.0	100.0	100.0	100.0
Heat Content,LHV (Btu/lb)		23,839	23,839	23,839	23,839	23,839
Natural Gas (lb/hr)		4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
Heat Content,LHV (Btu/cf)		950	950	950	950	950
Natural Gas (cf/hr)		105,263	105,263	105,263	105,263	105,263
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)		5,244	5,244	5,244	5,244	5,244
Temperature (°F)		200	200	200	200	200
Molecular Weight		28.00	28.00	28.00	28.00	28.00
Volume Flow (acfm)		1,504	1,504	1,504	1,504	1,504
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)		5,244	5,244	5,244	5,244	5,244
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.00	28.00	28.00	28.00	28.00
Volume Flow (scfm)		1,203	1,203	1,203	1,203	1,203
HRSG Stack Data						
Stack Height (ft)		180	180	180	180	180
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Volume Flow (acfm) from DB= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from DB		1,504	1,504	1,504	1,504	1,504
Assumed DB Exhaust Temp.(°F)		200	200	200	200	200
HRSG Temperature (°F)		200	200	200	200	200
Volume Flow (acfm) from DB		1,504	1,504	1,504	1,504	1,504
Velocity (ft/sec)= Volume flow (acfm) from DB ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from DB		1,504	1,504	1,504	1,504	1,504
Diameter (ft)		18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)		0.1	0.1	0.1	0.1	0.1

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft²

Source: Destec Engineering, Inc., 1992

Table A-12A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant		Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8760	8760	8760	8760	8760
Particulate (lb/hr)= Basis (lb/MMBtu) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.01	0.01	0.01	0.01	0.01
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		1.00	1.00	1.00	1.00	1.00
TPY		4.38	4.38	4.38	4.38	4.38
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)		105,263	105,263	105,263	105,263	105,263
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
lb/hr		0.30	0.30	0.30	0.30	0.30
TPY		1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides (lb/hr)= Basis (lb/MMBtu/hr) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.10	0.10	0.10	0.10	0.10
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		10.00	10.00	10.00	10.00	10.00
TPY		43.80	43.80	43.80	43.80	43.80
Carbon Monoxide (lb/hr)= Basis (lb/MMBtu) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.10	0.10	0.10	0.10	0.10
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		10.00	10.00	10.00	10.00	10.00
TPY		43.80	43.80	43.80	43.80	43.80
VOCs (lb/hr)= Basis (lb/MMBtu) x HIR (MMBtu/hr)						
Basis, lb/MMBtu		0.029	0.029	0.029	0.029	0.029
HIR, MMBtu/hr		100.0	100.0	100.0	100.0	100.0
lb/hr		2.90	2.90	2.90	2.90	2.90
TPY		12.70	12.70	12.70	12.70	12.70
Lead (lb/hr)= Negligible						
Basis, lb/MMBtu		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

Table A-13A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8760	8760	8760	8760	8760
Arsenic (lb/hr)= Negligible						
Basis, 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
Beryllium (lb/hr)= Negligible						
Basis, 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
Mercury (lb/hr)= Negligible						
Basis, 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
Fluoride (lb/hr)= Negligible						
Basis, 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
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2						
Fraction SO2 (%)		8	8	8	8	8
SO2 (lb/hr)		0.30	0.30	0.30	0.30	0.30
lb H2SO4/lb SO2 (98/64)		1.53	1.53	1.53	1.53	1.53
lb/hr		3.68E-02	3.68E-02	3.68E-02	3.68E-02	3.68E-02
TPY		1.61E-01	1.61E-01	1.61E-01	1.61E-01	1.61E-01

Source: EPA, 1990

Table A-14A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27 °F	Natural Gas 64 °F	Natural Gas 72 °F	Natural Gas 79 °F	Natural Gas 97 °F
A	B	C	D	E	F	G
Hours of Operation		8760	8760	8760	8760	8760
Manganese (lb/hr)= Negligible						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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						
Basis, 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 MMBtu/10E+12 Btu						
Basis, lb/10E+12 Btu (1)		1.113	1.113	1.113	1.113	1.113
HIR (MMBtu/hr)		100.0	100.0	100.0	100.0	100.0
lb/hr		1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
TPY		4.87E-04	4.87E-04	4.87E-04	4.87E-04	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	88.12	88.12	88.12	88.12
HIR (MMBtu/hr)		100.0	100.0	100.0	100.0	100.0
lb/hr		8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
TPY		3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02

Source: (1) EPA, 1990

GE PG 7221 FA
DISTILLATE OIL
BASE LOAD
27 °F

12018C2/APPA-1
06/13/92

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS (BASE LOAD)

(From Table A-1 On Distillate Oil;
All Other Calculations on Spreadsheet are Identical.)

Table A-1: (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)

$183{,}700 \times 10{,}070/10^6 = 1{,}849.9 \times 10^6$ Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

$1{,}849.9 \times 10^6 \div 18{,}550 = 99{,}723$ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

3,743,000 lb/hr x 1,545 x (1,060°F + 460°F) ÷ (28.25 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= 2,450,287 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,743,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (28.25 x 2,116.8) ÷ 60

= 851,152 scfm

GE PG7221FA
Distillate Oil
Base Load
27°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,450,287 acfm x (205°F + 460°F) ÷ (1,060°F + 460°F)

= 1,072,001 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

1,072,001 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 70.2 ft/sec

<u>Table A-2</u>:

PM emissions in tons per year

17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

99,722.9 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 99.72 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - 11.59/100) - 10.96] x 2,116.8 lb/ft^2
x 2,450,287 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,060°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= 326.2 lb/hr

GE PG7221 FA
Distillate Oil
Base Load
27°F

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - 11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (1,060°F + 460°F) x 10^6)

= 98.4 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.0 ppm x (1-11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr + (1,545 x (1,060°F + 460°F) x 10^6)

= ~~6.56~~ 7.50 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr

Table A-3:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

99,722.9 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x ~~0.05~~ 0.08 (converted)

= 12.2 lb/hr

Tables A-4 and A-5:

EPA emission factor as noted in printout; example for manganese:

1,849.9 (MMBtu) x 14 lb/10^{12} Btu

= 2.59 x 10^{-2} lb/hr

Emission Calculations, Tables A3, A-4, A-5

Manufacturer/Model: GE PG7221FA
Fuel Type: Distillate Oil
Load: Base
Ambient Temperature: 27°F

Arsenic: 4.2 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 7.77×10^{-3} lb/hr

Beryllium: 2.5 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 4.62×10^{-3} lb/hr

Mercury: 3.0 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 5.55×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 6.02×10^{-2} lb/hr

Nickel: 170.0 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.314 lb/hr

Cadmium: 10.5 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 1.94×10^{-2} lb/hr

Chromium: 47.5 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 8.79×10^{-2} lb/hr

Copper: 280 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.518 lb/hr

Vanadium: 69.5 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.129 lb/hr

Selenium: 23.42 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 4.33×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 5.14×10^{-4} lb/hr

Formaldehyde: 405 $lb/10^{12}$ Btu x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.749 lb/hr

Antimony: 9.4 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 4.04×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 3.61×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 1.68×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1849.9 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 1.26 lb/hr

Chlorine: 0.5 ppm x 99722.9 lb/hr fuel oil ÷ 10^6 = 4.99×10^{-2} lb/hr

GE PG7221 FA
DISTILLATE OIL
BASE LOAD
72°F

7-29-92

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS (BASE LOAD)

(From Table A-1 On Distillate Oil;

All Other Calculations on Spreadsheet are Identical.)

Table A-1: (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)

~~183,700~~ 159,200 x ~~10,070~~ 10,320/10^6 = ~~1,849.9~~ 1,642.9 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,642.9 x 10^6 ÷ 18,550 = ~~99,723~~ 88,568.4 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,390,000 lb/hr x 1,545 x (~~1,060~~ 1,102°F + 460°F) ÷ (~~28.25~~ 28.15 x 2,116.8 lb/ft²)
÷ 60(min/hr)

= ~~2,450,287~~ 2,288,314 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,390,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.15 x 2,116.8) ÷ 60
= ~~851,152~~ 773,514 scfm

GE PG7221FA
Distillate Oil
Base Load
72°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 2,288,314 acfm x (205°F + 460°F) ÷ (~~1,060~~ 1,102°F + 460°F)

= ~~1,072,001~~ 974,218 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

~~1,072,001~~ 974,218 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= ~~70.2~~ 63.8 ft/sec

Table A-2:

PM emissions in tons per year

17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

~~99,722.9~~ 88,568.4 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= ~~99.72~~ 88.57 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - ~~11.59~~ 12.40/100) - ~~10.96~~ 10.95] x 2,116.8 lb/ft^2
x ~~2,450,287~~ 2,288,314 ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~ 1,102°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 290.2 lb/hr

GE PG7221 FA
Distillate Oil
Base Load
72°F

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - ~~11.59~~ 12.40/100) x ~~2,450,287~~ 2,288,314 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (~~1,060~~ 1,102°F + 460°F) x 10^6)

= ~~98.4~~ 88.6 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 3.9 ppm x (1-~~11.59~~ 12.40/100) x ~~2,450,287~~ 2,288,314 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr + (1,545 x (~~1,060~~ 1,102°F + 460°F) x 10^6)

= ~~6.56~~ 6.58 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x ~~1,849.9~~ 1,642.9 x 10^6 Btu/hr = ~~1.65~~ 1.46 x 10^{-2} lb/hr

Table A-3:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

~~99,722.9~~ 88,568.4 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 10.8 lb/hr

Tables A-4 and A-5:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9~~ 1,642.9 (MMBtu) x 14 lb/10^{12} Btu

= ~~2.59~~ 2.30 x 10^{-2} lb/hr

Emission Calculations, Tables A-3, A-4, A-5

Manufacturer/Model: GE PG7221FA
Fuel Type: Distillate Oil
Load: Base
Ambient Temperature: 72°F

Arsenic: 4.2 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 6.9×10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 4.11×10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 4.93×10^{-3} lb/hr

Fluoride: 14 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 5.35×10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.279 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.73×10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 7.8×10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.460 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.114 lb/hr

Selenium: 23.42 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.85×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 4.57×10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.665 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 3.59×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 3.21×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 1.49×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1642.9 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 1.12 lb/hr

Chlorine: 0.5 ppm x 88,568.4 lb/hr fuel oil + 10^6 = 4.43×10^{-2} lb/hr

GE PG7221FA
DISTILLATE OIL
BASE LOAD
97°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97°F CONDITIONS (BASE LOAD)

(From Table A-1 On Distillate Oil;

All Other Calculations on Spreadsheet are Identical.)

<u>Table A-1</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)

~~183,700~~ 142,500 x ~~10,070~~ 10,650/10^6 = ~~1,849.9~~ 1,517.6 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,517.6 x 10^6 ÷ 18,550 = ~~99,723~~ 81,812.7 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,189,000 lb/hr x 1,545 x (~~1,060~~ 1,127°F + 460°F) ÷ (~~28.25~~ 28.10 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 2,190,589 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,189,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.10 x 2,116.8) ÷ 60

= ~~851,152~~ 728,816 scfm

GE PG7221FA
Distillate Oil
Base Load
97°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,190,589 ~~2,450,287~~ acfm x (205°F + 460°F) ÷ (1,127 ~~1,060~~°F + 460°F)

= ~~1,072,001~~ 917,922 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

917,922 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 60.1 ~~70.2~~ ft/sec

<u>Table A-2</u>:

PM emissions in tons per year

17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

81,812.7 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= ~~99.72~~ 81.81 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - 12.71 ~~11.59~~/100) - 11.03 ~~10.96~~] x 2,116.8 lb/ft^2
x ~~2,450,287~~ 2,190,589 ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,127 ~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 268.0 lb/hr

GE PG7221FA
Distillate Oil
Base Load
97°F

CO Emissions (lb/hr) - See Note C:

12.71 2,190,589

30 ppm x (1 - ~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28
(molecular wgt. of carbon)

1,127

x 60 min/hr ÷ (1,545 x (~~1,060~~°F + 460°F) x 10^6)

= ~~98.4~~ lb/hr
83.2

VOC Emissions (lb/hr) - See Note C:

4.1 12.71 2,190,589

~~3.5~~ ppm x (1-~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16
(molecular wgt. of methane)

1,127

x 60 min/hr ÷ (1,545 x (~~1,060~~°F + 460°F) x 10^6)

= ~~6.56~~ lb/hr
6.50

Lead Emissions (lb/hr):

1,517.6 1.35

8.9 lb/10^{12} Btu x ~~1,849.9~~ x 10^6 Btu/hr = ~~1.65~~ x 10^{-2} lb/hr

Table A-3:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

81,812.7 0.08

~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x ~~0.05~~
(converted)

= ~~12.2~~ lb/hr
10.0

Tables A-4 and A-5:

EPA emission factor as noted in printout; example for manganese:

1,517.6

~~1,849.9~~ (MMBtu) x 14 lb/10^{12} Btu

= ~~2.59~~ x 10^{-2} lb/hr
2.12

Emission Calculations, Tables A-3, A-4, A-5

Manufacturer/Model: GE PG7221FA
Fuel Type: Distillate Oil
Load: Base
Ambient Temperature: 97°F

Arsenic: 4.2 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 6.37×10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.79×10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 4.55×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 4.94×10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.258 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.59×10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 7.21×10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.425 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.105 lb/hr

Selenium: 23.42 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.55×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 4.22×10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.615 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.32×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.96×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.38×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1517.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.04 lb/hr

Chlorine: 0.5 ppm x 81,812.7 lb/hr fuel oil ÷ 10^6 = 4.09×10^{-2} lb/hr

GE PG7221 FA
NATURAL GAS
BASE LOAD
27 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS

(From Table A-6 On ~~Distillate Oil~~ Natural Gas; Base Load
All Other Calculations on Spreadsheet are Identical.)

Table A-~~2~~6: (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)
~~183,700~~ 170,700 x ~~10,070~~ 9,460/10^6 = ~~1,849.9~~ 1,614.8 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)
~~1,849.9~~ 1,614.8 x 10^6 ÷ ~~18,550~~ 21,515 = ~~99,725~~ 75,055.6 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM
~~3,743,000~~ 3,582,000 lb/hr x 1,545 x (~~1,060~~ 1,078°F + 460°F) ÷ (~~28.25~~ 28.46 x 2,116.8 lb/ft²)

÷ 60(min/hr)
= ~~2,450,287~~ 2,354,349 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,582,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.46 x 2,116.8) ÷ 60
= ~~851,152~~ 808,255 scfm

GE PG7221 FA
Natural Gas
Base Load
27°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 2,354,349 acfm x (205°F + 460°F) ÷ (~~1,060~~ 1,078°F + 460°F)

= ~~1,072,001~~ 1,017,973 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

~~1,072,001~~ 1,017,973 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= ~~70.2~~ 66.7 ft/sec

<u>Table A-~~2~~ 7</u>:

PM emissions in tons per year

~~17~~ 9.0 lb/hr x ~~300~~ 8460 hr/yr ÷ 2,000 lb/ton

= ~~2.6~~ 38.07 ton/yr

SO_2 Emissions - ~~Oil~~ Gas (lb/hr)

~~99,722.9 lb/hr~~ 1,699,813 cf/hr x ~~0.0005 lb S/lb~~ 1.0 gr/100cf x 2 lb SO_2/lb S x 1.0 lb/7000gr

= ~~99.72~~ 4.86 lb/hr

NO_x Emissions (lb/hr) - See Note B:

~~42~~ 25 ppm x [20.9 x (1 - ~~11.59~~ 7.61/100) - ~~10.96~~ 12.71] x 2,116.8 lb/ft^2

x ~~2,450,287~~ 2,354,349 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~ 1,078°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 161.9 lb/hr

GE PG7221FA
Natural Gas
Base Load
27°F

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12018C2/APPA-3
~~06/12/92~~
7/29/92

CO Emissions (lb/hr) - See Note C:

15 ~~50~~ ppm x (1 - 7.61 ~~11.59~~/100) x 2,354,349 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,078 ~~1,060~~°F + 460°F) x 10^6)

= 48.8 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

1.5 ~~3.5~~ ppm x (1- 7.61 ~~11.59~~/100) x 2,354,349 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,078 ~~1,060~~°F + 460°F) x 10^6)

= 2.79 ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-8 ~~4~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,699,813 cf/hr x 1.0 gr/100cf x 2 lbSO_2/lbS x 1.0 lb/7000gr
~~99,722.9 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S~~ x 0.08 ~~0.05~~ x 1.53 lbH_2S / lbS
(converted)

= 0.595 ~~12.2~~ lb/hr

Tables A-8, A-9, A-10 ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/29/92

Emission Calculations, Tables A-8, A-9, A-10

Manufacturer/Model: GE PG 7221 FA
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 27°F

Arsenic: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Nickel: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: ______ lb/10^{12} Btu x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1614.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= 1.8×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1614.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.142 lb/hr

Antimony: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Barium: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Cobalt: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Zinc: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Chlorine: ______ ppm x ________ lb/hr fuel oil + 10^6 = NA lb/hr

'GE PG7221 FA
NATURAL GAS
BASE LOAD
64 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 64 ~~27~~°F CONDITIONS

(From Table A-6 On Natural Gas ~~Distillate Oil~~; Base Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~5~~ 6: (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)

151,900 ~~183,700~~ x 9,750 ~~10,070~~/10^6 = 1,481.0 ~~1,849.9~~ x 10^6 Btu/hr

Natural Gas ~~Fuel Oil~~ (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,481.0 ~~1,849.9~~ x 10^6 ÷ 21,515 ~~18,550~~ = 68,836.9 ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

3,322,000 ~~3,743,000~~ lb/hr x 1,545 x (1,110 ~~1,060~~°F + 460°F) ÷ (28.33 ~~28.25~~ x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= 2,239,805 ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,322,000 ~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (28.33 ~~28.25~~ x 2,116.8) ÷ 60

= 753,259 ~~851,152~~ scfm

GE PG7221 FA
Natural Gas
Base Load
64°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,239,805 ~~2,450,287~~ acfm x (205 ~~205~~°F + 460°F) + (1,110 ~~1,060~~°F + 460°F)

= 948,707 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

948,707 ~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 62.1 ~~70.2~~ ft/sec

Table A-7 ~~2~~:

PM emissions in tons per year

9.0 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr + 2,000 lb/ton

= 38.07 ~~2.6~~ ton/yr

SO_2 Emissions--Gas ~~Oil~~ (lb/hr)

1,558,974 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 4.45 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 ~~42~~ ppm x [20.9 x (1 - 8.83 ~~11.59~~/100) - 12.56 ~~10.96~~] x 2,116.8 lb/ft^2

x 2,239,805 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (1,110 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 148.5 ~~326.2~~ lb/hr

GE PG7221 FA
Natural Gas
Base Load
64°F

CO Emissions (lb/hr) - See Note C:

15 ~~30~~ ppm x (1 - 8.83 ~~11.59~~/100) x 2,239,805 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,110 ~~1,060~~°F + 460°F) x 10^6)

= 44.9 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

1.5 ~~3.5~~ ppm x (1-8.83 ~~11.59~~/100) x 2,239,805 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,110 ~~1,060~~°F + 460°F) x 10^6)

= 2.57 ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table A-8 ~~3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,558,974 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr ~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x 1.53 ~~3.06~~ lb H_2SO_4/lb SO_2 x 0.08 ~~0.05~~ (converted)

= 0.546 ~~12.2~~ lb/hr

Tables A-8, A-9, A-10 ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

7/29/92

Emission Calculations, Tables A-8, A-9, A-10

Manufacturer/Model: GE PG7221FA
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 64°F

Arsenic: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Nickel: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: ____ lb/10^{12} Btu x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1481.0 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= 1.65×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1481.0 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.131 lb/hr

Antimony: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Barium: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Cobalt: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Zinc: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Chlorine: ____ ppm x ______ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG 7221 FA
NATURAL GAS
72 °F
BASE LOAD

12018C2/APPA-1
~~06/13/92~~
7/30/92

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS

(From Table A-~~2~~ 6 On ~~Distillate Oil~~ Natural Gas; Base Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~2~~ 6: (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)

~~183,700~~ 147,100 x ~~10,070~~ 9860/10^6 = ~~1,849.9~~ 1,450.4 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,450.4 x 10^6 ÷ ~~18,550~~ 21,515 = ~~99,723~~ 67,413.7 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,262,000 lb/hr x 1,545 x (~~1,060~~ 1,117°F + 460°F) ÷ (~~28.25~~ 28.28 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 2,212,530 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,262,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.28 x 2,116.8) ÷ 60

= ~~851,152~~ 740,784 scfm

GE PG7221 FA
Natural Gas
72°F
Base Load

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,212,530 ~~2,450,287~~ acfm x (205°F + 460°F) ÷ (1,117 ~~1,060~~°F + 460°F)

= 932,995 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

932,995 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 61.1 ~~70.2~~ ft/sec

Table A-7 ~~2~~:

PM emissions in tons per year

9.0 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr ÷ 2,000 lb/ton

= 38.07 ~~2.6~~ ton/yr

SO_2 Emissions--Gas ~~Oil~~ (lb/hr)

1,526,743 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 4.36 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 ~~42~~ ppm x [20.9 x (1 - 9.21 ~~11.59~~/100) - 12.51 ~~10.96~~] x 2,116.8 lb/ft^2

x 2,212,530 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,117 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 145.3 ~~326.2~~ lb/hr

GE PG7221FA
Natural Gas
Base Load
72°F

CO Emissions (lb/hr) - See Note C:

$\cancel{30}$ 15 ppm x (1 - $\cancel{11.59}$ 9.21/100) x $\cancel{2,450,287}$ 2,212,530 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x ($\cancel{1,060}$ 1,117°F + 460°F) x 10^6)

= ~~98.4~~ 44.0 lb/hr

VOC Emissions (lb/hr) - See Note C:

$\cancel{3.5}$ 1.5 ppm x (1-$\cancel{11.59}$ 9.21/100) x $\cancel{2,450,287}$ 2,212,530 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x ($\cancel{1,060}$ 1,117°F + 460°F) x 10^6)

= ~~6.56~~ 2.51 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table A-~~6~~8:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,526,743 cf/hr x 1.0 gr/100cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.534 lb/hr

Tables ~~A-4 and A-5~~ A-8, A-9, A-10:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

Emission Calculations, Tables A-8, A-9, A-10

Manufacturer/Model: GE PG7221 FA
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 72°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1450.4 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.61×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1450.4 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.128 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: _____ ppm x ________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG 7221 FA
NATURAL GAS
79°F
BASE LOAD

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 79°F CONDITIONS

(From Table A-~~2~~ 6 On ~~Distillate Oil~~ Natural Gas; Base Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~2~~ 6: (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)

142,700 9970 1,422.7
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Natural Gas
~~Fuel Oil~~ (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,422.7 21,515 66,126.8
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

3,202,000 1,124 28.19
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (~~28.25~~ x 2,116.8 lb/ft²)

÷ 60(min/hr)

2,188,744
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,202,000 28.19
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ x 2,116.8) ÷ 60

729,581
= ~~851,152~~ scfm

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GE PG7221FA
Natural Gas
79°F
Base Load

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,188,744 1,124

~~2,450,287~~ acfm x (205°F + 460°F) + (~~1,060~~°F + 460°F)

918,885

= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

918,885

~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

60.2

= ~~70.2~~ ft/sec

7

Table A-~~2~~:

PM emissions in tons per year

9.0 8460

~~17~~ lb/hr x ~~300~~ hr/yr + 2,000 lb/ton

38.07

= ~~2.6~~ ton/yr

Gas

SO_2 Emissions--~~Oil~~ (lb/hr)

1,497,599 cf/hr 1.0 gr/100 cf

~~99,722.9 lb/hr~~ x ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

4.28

= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 10.05 12.36

~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2

x ~~2,450,287~~ ft^3/min

2,188,744 1,124

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

142.6

= ~~326.2~~ lb/hr

PG 7221FA
Natural Gas
Base Load
79°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 15 ppm x (1 - ~~11.59~~ 10.05/100) x ~~2,450,287~~ 2,188,744 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,124°F + 460°F) x 10^6)

= ~~98.4~~ 42.9 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 1.6 ppm x (1-~~11.59~~ 10.05/100) x ~~2,450,287~~ 2,188,744 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,124°F + 460°F) x 10^6)

= ~~6.56~~ 2.62 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-~~9~~ 8:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,497,599 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr
~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.524 lb/hr

Tables ~~A-4 and A-5~~ A-8, A-9, A-10:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/30/92

Emission Calculations, Tables A-8, A-9, A-10

Manufacturer/Model: GE PG7221 FA
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 79°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1422.7 MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= 1.58×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1422.7 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.125 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Chlorine: _____ ppm x ________ lb/hr fuel oil + 10^6 = NA lb/hr

GE PG 7221 FA
NATURAL GAS
BASE LOAD
97 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97°F CONDITIONS

(From Table A-~~1~~ 6 On ~~Distillate Oil~~ Natural Gas; Base Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 6: (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)

~~183,700~~ 131,800 x ~~10,070~~ 10,230/10^6 = ~~1,849.9~~ 1348.3 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1348.3 x 10^6 ÷ ~~18,550~~ 21,515 = ~~99,723~~ 62,668.6 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,077,000 lb/hr x 1,545 x (~~1,060~~ 1,140°F + 460°F) ÷ (~~28.25~~ 28.20 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 2,123,643 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of

68°F

~~3,743,000~~ 3,077,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.20 x 2,116.8) ÷ 60

= ~~851,152~~ 700,802 scfm

GE PG 7221 FA
Natural Gas
Base Load
97°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,123,643 1,140
~~2,450,287~~ acfm x (205°F + 460°F) ÷ (~~1,060~~°F + 460°F)

882,639
= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

882,639
~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

57.8
= ~~70.2~~ ft/sec

7
Table A-~~8~~:

PM emissions in tons per year

9.0 8460
~~17~~ lb/hr x ~~300~~ hr/yr ÷ 2,000 lb/ton

38.07
= ~~2.6~~ ton/yr

Gas
SO_2 Emissions--~~Oil~~ (lb/hr)

1,419,278 cf/hr 1.0 gr/100 cf
~~99,722.9 lb/hr~~ x ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

4.06
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 9.91 12.48
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2

x ~~2,450,287~~ ft^3/min
2,123,643

1,140
x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

135.0
= ~~326.2~~ lb/hr

GE PG7221FA
Natural Gas
Base Load
97°F

CO Emissions (lb/hr) - See Note C:

15 / 9.91 / 2,123,643

~~90~~ ppm x (1 - ~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft² x 28 (molecular wgt. of carbon)

1,140

x 60 min/hr ÷ (1,545 x (~~1,060~~°F + 460°F) x 10⁶)

41.3

= ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

1.5 / 9.91 / 2,123,643

~~3.5~~ ppm x (1-~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft² x 16 (molecular wgt. of methane)

1,140

x 60 min/hr ÷ (1,545 x (~~1,060~~°F + 460°F) x 10⁶)

2.36

= ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~0.9 lb/10¹² Btu x 1,849.9 x 10⁶ Btu/hr = 1.65 x 10⁻² lb/hr~~

8

Table A-~~3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,419,278 cf/hr x 1.0 gr/100 cf x 2 lb SO_2 / lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

0.497

= ~~12.2~~ lb/hr

A-8, A-9, A-10

Tables ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10¹² Btu~~ Not Applicable

~~= 2.59 x 10⁻² lb/hr~~

7/30/92

Emission Calculations, Tables A-8, A-9, A-10

Manufacturer/Model: GE PG7221 FA
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 97°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1348.3 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.50×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1348.3 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.119 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: _____ ppm x _______ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG7221 FA
DISTILLATE OIL
70% LOAD
27 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS (70% LOAD)

(From Table A-1A On Distillate Oil;

All Other Calculations on Spreadsheet are Identical.)

Table A-1A: (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)

129,200 11,430 1,476.8
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,476.8 79,609.5
~~1,849.9~~ x 10^6 ÷ 18,550 = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

2,837,000 1,166 28.23
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (~~28.25~~ x 2,116.8 lb/ft²)

÷ 60(min/hr)

1,988,010
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

2,837,000 28.23
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ x 2,116.8) ÷ 60

= ~~851,152~~ scfm
643,553

GE PG7221FA
Distillate Oil
70% Load
27°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 1,988,010 acfm x (~~205~~ 200°F + 460°F) ÷ (~~1,060~~ 1,166°F + 460°F)

= ~~1,072,001~~ 806,941 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

~~1,072,001~~ 806,941 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= ~~70.2~~ 52.9 ft/sec

<u>Table A-2A</u>:

PM emissions in tons per year

17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

~~99,722.9~~ 79,609.5 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= ~~99.72~~ 79.61 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - ~~11.59~~ 11.96/100) - ~~10.96~~ 10.57] x 2,116.8 lb/ft^2
x ~~2,450,287~~ 1,988,010 ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~ 1,166°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 257.7 lb/hr

GE PG7221FA
Distillate Oil
70% Load
27°F

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - 11.96 ~~11.59~~/100) x 1,988,010 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28
(molecular wgt. of carbon)

x 60 min/hr + (1,545 x (1,166 ~~1,060~~°F + 460°F) x 10^6)

= 74.3 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

4.0 ~~3.5~~ ppm x (1-11.96 ~~11.59~~/100) x 1,988,010 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16
(molecular wgt. of methane)

x 60 min/hr + (1,545 x (1,166 ~~1,060~~°F + 460°F) x 10^6)

= ~~6.56~~ 5.66 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x 1,476.8 ~~1,849.9~~ x 10^6 Btu/hr = 1.31 ~~1.65~~ x 10^{-2} lb/hr

Table A-3A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

79,609.5 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.08 ~~0.05~~
(converted)

= ~~12.2~~ 9.75 lb/hr

Tables A-4A and A-5A:

EPA emission factor as noted in printout; example for manganese:

1,476.8 ~~1,849.9~~ (MMBtu) x 14 lb/10^{12} Btu

= ~~2.59~~ 2.07 x 10^{-2} lb/hr

Emission Calculations, Tables A-3A, A-4A, A-5A

Manufacturer/Model: GE PG7221FA
Fuel Type: Distillate Oil
Load: 70%
Ambient Temperature: 27°F

Arsenic: 4.2 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 6.2×10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.69×10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 4.43×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 4.8×10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.251 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.55×10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 7.01×10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.413 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.103 lb/hr

Selenium: 23.42 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.46×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 4.11×10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.598 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.23×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 2.88×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.34×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1476.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.01 lb/hr

Chlorine: 0.5 ppm x 79609.5 lb/hr fuel oil + 10^6 = 3.98×10^{-2} lb/hr

GE PG 7221 FA
DISTILLATE OIL
70% LOAD
72°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS (70% LOAD)

(From Table A-1A On Distillate Oil;

All Other Calculations on Spreadsheet are Identical.)

Table A-1A: (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)

~~183,700~~ 111,000 x ~~10,070~~ 11,800/10^6 = ~~1,849.9~~ 1,309.8 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) + Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,309.8 x 10^6 + 18,550 = ~~99,723~~ 70,609.2 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,619,000 lb/hr x 1,545 x (~~1,060~~ 1,192°F + 460°F) + (~~28.25~~ 28.16 x 2,116.8 lb/ft^2)

+ 60(min/hr)

= ~~2,450,287~~ 1,869,045 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,619,000 lb/hr x 1,545 x (68°F + 460°F) + (~~28.25~~ 28.16 x 2,116.8) + 60

= ~~851,152~~ 597,370 scfm

GE PG 7221FA
Distillate Oil
70% Load
72°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,869,045 ~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) + (1,192 ~~1,060~~°F + 460°F)

= 746,713 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

746,713 ~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 48.9 ~~70.2~~ ft/sec

<u>Table A-2A</u>:

PM emissions in tons per year

17 lb/hr x 300 hr/yr + 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

70,609.2 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 70.61 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - 12.40 ~~11.59~~/100) - 10.81 ~~10.96~~] x 2,116.8 lb/ft^2
x 1,869,045 ~~2,450,287~~ ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (1,192 ~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= 228.4 ~~326.2~~ lb/hr

GE PG7221FA
Distillate Oil
70% Load
72°F

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - ~~11.59~~ 12.40/100) x ~~2,450,287~~ 1,869,045 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,192°F + 460°F) x 10^6)

= ~~98.4~~ 68.4 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.0 ppm x (1-~~11.59~~ 12.40/100) x ~~2,450,287~~ 1,869,045 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,192°F + 460°F) x 10^6)

= ~~6.56~~ 5.21 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x ~~1,849.9~~ 1,309.8 x 10^6 Btu/hr = ~~1.65~~ 1.17 x 10^{-2} lb/hr

<u>Table A-3A:</u>

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

~~99,722.9~~ 70,609.2 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 8.65 lb/hr

<u>Tables A-4A and A-5A:</u>

EPA emission factor as noted in printout; example for manganese:

~~1,849.9~~ 1,309.8 (MMBtu) x 14 lb/10^{12} Btu

= ~~2.59~~ 1.83 x 10^{-2} lb/hr

Emission Calculations, Tables A-3A, A-4A, A-5A

Manufacturer/Model: PG7221FA
Fuel Type: Distillate Oil
Load: 70%
Ambient Temperature: 72°F

Arsenic: 4.2 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 5.5×10^{-3} lb/hr

Beryllium: 2.5 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 3.27×10^{-3} lb/hr

Mercury: 3.0 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 3.93×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 4.26×10^{-2} lb/hr

Nickel: 170 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.223 lb/hr

Cadmium: 10.5 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 1.38×10^{-2} lb/hr

Chromium: 47.5 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 6.22×10^{-2} lb/hr

Copper: 280 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.367 lb/hr

Vanadium: 69.5 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 9.1×10^{-2} lb/hr

Selenium: 23.42 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 3.07×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 3.64×10^{-4} lb/hr

Formaldehyde: 405 $lb/10^{12}$ Btu x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.53 lb/hr

Antimony: 9.4 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 2.86×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 2.56×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 1.19×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1309.8 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.895 lb/hr

Chlorine: 0.5 ppm x 79609.5 lb/hr fuel oil ÷ 10^6 = 3.53×10^{-2} lb/hr

GE PG 7221 FA
DISTILLATE OIL
70% LOAD
97 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97°F CONDITIONS (70% LOAD)

(From Table A-1A On Distillate Oil;

All Other Calculations on Spreadsheet are Identical.)

Table A-1A: (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)

~~183,700~~ 98,500 x ~~10,070~~ 12,280/10^6 = ~~1,849.9~~ 1,209.6 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,209.6 x 10^6 ÷ 18,550 = ~~99,723~~ 65,206.5 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,510,000 lb/hr x 1,545 x (~~1,060~~ 1,200°F + 460°F) ÷ (~~28.25~~ 28.13 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,802,083 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,510,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.13 x 2,116.8) ÷ 60

= ~~851,152~~ 573,193 scfm

GE PG7221 FA
Distillate Oil
70% Load
97°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 1,802,083 acfm x (~~205~~ 200°F + 460°F) + (~~1,060~~ 1,200°F + 460°F)

= ~~1,072,001~~ 716,491 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

~~1,072,001~~ 716,491 ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= ~~70.2~~ 46.9 ft/sec

Table A-2A:

PM emissions in tons per year

17 lb/hr x 300 hr/yr + 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

~~99,722.9~~ 65,206.5 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= ~~99.72~~ 65.21 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - ~~11.59~~ 12.48/100) - ~~10.96~~ 11.07] x 2,116.8 lb/ft^2
x ~~2,450,287~~ 1,802,083 ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~ 1,200°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 211.0 lb/hr

GE PG7221 FA
Distillate Oil
70% Load
97°F

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - ~~11.59~~ 12.48/100) x ~~2,450,287~~ 1,802,083 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,200°F + 460°F) x 10^6)

= ~~98.4~~ 65.6 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.1 ppm x (1-~~11.59~~ 12.48/100) x ~~2,450,287~~ 1,802,083 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,200°F + 460°F) x 10^6)

= ~~6.56~~ 5.12 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x ~~1,849.9~~ 1,209.6 x 10^6 Btu/hr = ~~1.65~~ 1.08 x 10^{-2} lb/hr

Table A-3A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

~~99,722.9~~ 65,206.5 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 7.99 lb/hr

Tables A-4A and A-5A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9~~ 1,209.6 (MMBtu) x 14 lb/10^{12} Btu

= ~~2.59 x 10^{-2}~~ 1.69 x 10^{-2} lb/hr

Emission Calculations, Tables A-3A, A-4A, A-5A

Manufacturer/Model: GE PG7221 FA
Fuel Type: Distillate Oil
Load: 70%
Ambient Temperature: 97°F

Arsenic: 4.2 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 5.08×10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.02×10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.63×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.94×10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.206 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.27×10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 5.75×10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.339 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 8.41×10^{-2} lb/hr

Selenium: 23.42 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.83×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.36×10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.490 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.64×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.36×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.10×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1209.6 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.826 lb/hr

Chlorine: 0.5 ppm x 65206.5 lb/hr fuel oil ÷ 10^6 = 3.26×10^{-2} lb/hr

GE PG7221 FA
NATURAL GAS
70% LOAD
27 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS

(From Table A-~~1~~ 6A On ~~Distillate Oil~~ Natural Gas; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 6A: (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)

~~183,700~~ 119,900 x ~~10,070/10⁶~~ 10,770 = ~~1,849.9~~ 1291.3 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,291.3 x 10^6 ÷ ~~18,550~~ 21,515 = ~~99,723~~ 60,019.7 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,744,000 lb/hr x 1,545 x (~~1,060~~ 1,177°F + 460°F) ÷ (~~28.25~~ 28.45 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,920,685 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,744,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.45 x 2,116.8) ÷ 60

= ~~851,152~~ 619,500 scfm

GE PG7221 FA
Natural Gas
70% LOAD
27°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 1,920,685 acfm x (~~205~~ 200°F + 460°F) ÷ (~~1,060~~ 1,177°F + 460°F)

= ~~1,072,001~~ 774,375 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

~~1,072,001~~ 774,375 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= ~~70.2~~ 50.7 ft/sec

Table A-~~2~~ 7A:

PM emissions in tons per year

~~17~~ 9.0 lb/hr x ~~300~~ 8460 hr/yr ÷ 2,000 lb/ton

= ~~2.6~~ 38.07 ton/yr

SO_2 Emissions-~~Oil~~ GAS (lb/hr)

1,359,287 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= ~~99.72~~ 3.88 lb/hr

NO_x Emissions (lb/hr) - See Note B:

~~42~~ 25 ppm x [20.9 x (1 - ~~11.59~~ 7.84/100) - ~~10.96~~ 12.46] x 2,116.8 lb/ft^2

x ~~2,450,287~~ 1,920,685 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [~~1,545~~ stet x (~~1,060~~ 1,177°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 127.9 lb/hr

GE PG7221FA
Natural Gas
70% LOAD
27°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 15 ppm x (1 - ~~11.59~~ 7.84/100) x ~~2,450,287~~ 1,920,685 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,177°F + 460°F) x 10^6)

= ~~98.4~~ 373 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 1.5 ppm x (1- ~~11.59~~ 7.84/100) x ~~2,450,287~~ 1,920,685 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,177°F + 460°F) x 10^6)

= ~~6.56~~ 2.13 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-~~5~~ 8A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

(1,359,287 cf/hr x 1.0 gr/100 Cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr) ~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.476 lb/hr

Tables ~~A-4 and A-5~~ A-8A, A-9A, A-10A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/30/92

Emission Calculations, Tables A-8A, A-9A, A-10A

Manufacturer/Model: GE PG7221 FA
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 27°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1291.3 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.44×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1291.3 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.114 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: _____ ppm x _________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG 7221 FA
NATURAL GAS
70% LOAD
64°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 64°F CONDITIONS

(From Table A-~~5~~ 6A On ~~Distillate Oil~~ Natural Gas; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~5~~ 6A: (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)

106,500 11,070 1,179.0
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Natural Gas
~~Fuel Oil~~ (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,179.0 21,515 54,796.9
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

2,595,000 1,195 28.32
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (~~28.25~~ x 2,116.8 lb/ft^2)

÷ 60(min/hr)

1,845,077
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

2,595,000 28.32
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ x 2,116.8) ÷ 60

588,641
= ~~851,132~~ scfm

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GE PG7221FA
Natural Gas
70% LOAD
64°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,845,077 200 1,195
~~2,450,287~~ acfm x (~~205~~°F + 460°F) + (~~1,060~~°F + 460°F)
735,801
= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

735,801
~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)
48.2
= ~~70.2~~ ft/sec

A-7A
Table ~~A-2~~:

PM emissions in tons per year

9.0 8460
~~17~~ lb/hr x ~~300~~ hr/yr + 2,000 lb/ton
38.07
= ~~2.6~~ ton/yr

Gas
SO_2 Emissions--~~oil~~ (lb/hr)
1,241,005 cf/hr 1.0 gr/100 cf
~~99,722.9 lb/hr~~ x ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1 lb/7000 gr
3.55
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 8.98 12.41
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2
x ~~2,450,287~~ ft^3/min
1,845,077
1,195
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]
118.1
= ~~326.2~~ lb/hr

GE PG7221 FA
Natural Gas
70% Load
61°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 15 ppm x (1 - ~~11.59~~ 8.98/100) x ~~2,450,287~~ 1,845,077 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,195°F + 460°F) x 10^6)

= ~~98.4~~ 35.0 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 1.5 ppm x (1-~~11.59~~ 8.98/100) x ~~2,450,287~~ 1,845,077 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,195°F + 460°F) x 10^6)

= ~~6.56~~ 2.00 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table ~~A-3~~ A-8A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,241,005 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.434 lb/hr

Tables ~~A-4 and A-5~~ A-8A, A-9A, A-10A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

7/30/92

Emission Calculations, Tables A-8A, A-9A, A-10A

Manufacturer/Model: GE PG7221 FA
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 64°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1179.0 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= 1.31×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1179.0 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.104 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Chlorine: _____ ppm x _________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG7221 FA
NATURAL GAS
70% LOAD
72°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS

(From Table A-~~1~~ 6A On ~~Distillate Oil~~ NATURAL GAS; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~5~~ 6A: (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)

~~183,700~~ 103,100 x ~~10,070~~ 11,340/10^6 = ~~1,849.9~~ 1169.2 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1169.2 x 10^6 ÷ ~~18,550~~ 21,515 = ~~99,723~~ 54,341.3 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,560,000 lb/hr x 1,545 x (~~1,060~~ 1,199°F + 460°F) ÷ (~~28.25~~ 28.27 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,827,352 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,560,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.27 x 2,116.8) ÷ 60

= ~~851,152~~ 581,580 scfm

GE PG 7221 FA
Natural Gas
70% LOAD
72°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,827,352 200 1,199
~~2,450,287~~ acfm x (~~205~~°F + 460°F) + (~~1,060~~°F + 460°F)
726,975
= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

726,975
~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)
47.6
= ~~70.2~~ ft/sec

<u>Table A-~~2~~7A:</u>

PM emissions in tons per year

9.0 8460
~~17~~ lb/hr x ~~300~~ hr/yr + 2,000 lb/ton
38.07
= ~~2.6~~ ton/yr

Gas
SO_2 Emissions--~~Oil~~ (lb/hr)

1,230,688 cf/hr 1.0 gr/100 cf
~~99,722.9 lb/hr~~ x ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr
3.52
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 9.34 12.39
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2
x ~~2,450,287~~ ft^3/min
1,827,352 1,199
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]
115.7
= ~~326.2~~ lb/hr

GE PG7221FA
Natural Gas
70% LOAD
72°F

12018C2/APPA-3
~~06/12/92~~
7/30/92

CO Emissions (lb/hr) - See Note C:

~~30~~ 15 ppm x (1 - ~~11.59~~ 9.34/100) x ~~2,450,287~~ 1,827,352 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,199°F + 460°F) x 10^6)

= ~~98.4~~ 34.5 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 1.5 ppm x (1-~~11.59~~ 9.34/100) x ~~2,450,287~~ 1,827,352 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,199°F + 460°F) x 10^6)

= ~~6.56~~ 2.00 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-~~3~~ 8A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

(1,230,688 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr) ~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.431 lb/hr

Tables ~~A-4 and A-5~~ A-8A, A-9A, A-10A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/30/92

Emission Calculations, Tables A-8A, A-9A, A-10A

Manufacturer/Model: GE PG7221FA
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 72°F

Arsenic: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Nickel: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x 1169.2 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= 1.3×10^{-3} lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x 1169.2 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.103 lb/hr

Antimony: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Barium: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Cobalt: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Zinc: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Chlorine: _____ ppm x ________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG7221 FA
NATURAL GAS
70% LOAD
79°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 79°F CONDITIONS

(From Table A-~~1~~ 6A On ~~Distillate Oil~~ NATURAL GAS; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 6A: (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)

~~183,700~~ 99 500 x ~~10,070~~ 11,510 /10^6 = ~~1,849.9~~ 1,145.2 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,145.2 x 10^6 ÷ ~~18,550~~ 21,515 = ~~99,723~~ 53,230.1 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,524,000 lb/hr x 1,545 x (~~1,060~~ 1,200°F + 460°F) ÷ (~~28.25~~ 28.18 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,808,470 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,524,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.18 x 2,116.8) ÷ 60

= ~~851,152~~ 575,224 scfm

GE PG7221FA
Natural Gas
70% LOAD
79°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 1,808,470 acfm x (~~205~~ 200°F + 460°F) ÷ (~~1,060~~ 1,200°F + 460°F)

= ~~1,072,001~~ 719,030 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

~~1,072,001~~ 719,030 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= ~~70.2~~ 47.1 ft/sec

<u>Table A-~~2~~ 7A:</u>

PM emissions in tons per year

~~17~~ 9.0 lb/hr x ~~300~~ 8460 hr/yr ÷ 2,000 lb/ton

= ~~2.6~~ 38.07 ton/yr

SO_2 Emissions - ~~Oil~~ GAS (lb/hr)

~~99,722.9 lb/hr~~ 1,205,521 cf/hr x ~~0.0005 lb S/lb~~ 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= ~~99.72~~ 3.44 lb/hr

NO_x Emissions (lb/hr) - See Note B:

~~42~~ 25 ppm x [20.9 x (1 - ~~11.59~~ 10.14/100) - ~~10.96~~ 12.28] x 2,116.8 lb/ft^2
x ~~2,450,287~~ 1,808,470 ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~ 1,200°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 113.5 lb/hr

GE PG7221 FA
Natural Gas
70% LOAD
79°F

CO Emissions (lb/hr) - See Note C:

15 10.14 1,808,470
~~30~~ ppm x (1 - ~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

1,200
x 60 min/hr ÷ (1,545 x (~~1,060~~°F + 460°F) x 10^6)

338
= ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

1.6 10.14 1,808,470
~~3.5~~ ppm x (1-~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

1,200
x 60 min/hr ÷ (1,545 x (~~1,060~~°F + 460°F) x 10^6)

2.06
= ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

A-8A
Table ~~A-3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

(1,205,521 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr) 0.08
~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ (converted)

0.422
= ~~12.2~~ lb/hr

A-8A, A-9A, A-10A
Tables ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/30/92

Emission Calculations, Tables A-8A, A-9A, A-10A

Manufacturer/Model: PG 7221 FA
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 79°F

Arsenic: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Nickel: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x 1145.2 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= 1.27×10^{-3} lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x 1145.2 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 0.101 lb/hr

Antimony: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Barium: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Cobalt: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Zinc: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Chlorine: ____ ppm x ______ lb/hr fuel oil ÷ 10^6 = NA lb/hr

GE PG 7221 FA
NATURAL GAS
70% LOAD
97 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97°F CONDITIONS

(From Table A-~~1~~ 6A On ~~Distillate Oil~~ NATURAL GAS; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 6A: (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)

90,900 11,890 1,080.8
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

NATURAL GAS
~~Fuel Oil~~ (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,080.8 21,515 50,234.8
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

2,454,000 1,200 28.20
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (~~28.25~~ x 2,116.8 lb/ft²)

÷ 60(min/hr)

1,757,157
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

2,454,000 28.20
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ x 2,116.8) ÷ 60

558,903
= ~~851,152~~ scfm

GE PG7221 FA
Natural Gas
70% LOAD
97°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,757,157 ~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) + (1,200 ~~1,060~~°F + 460°F)

= 698,629 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

698,629 ~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 45.8 ~~70.2~~ ft/sec

Table A-7A ~~2~~:

PM emissions in tons per year

9.0 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr + 2,000 lb/ton

= 38.07 ~~2.6~~ ton/yr

SO_2 Emissions - GAS ~~Oil~~ (lb/hr)

1,137,685 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 3.25 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25 ~~42~~ ppm x [20.9 x (1 - 9.89 ~~11.59~~/100) - 12.52 ~~10.96~~] x 2,116.8 lb/ft^2

x 1,757,157 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (1,200 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 107.1 ~~326.2~~ lb/hr

GE PG7221 FA
Natural Gas
70% Load
97°F

CO Emissions (lb/hr) - See Note C:

15 ~~30~~ ppm x (1 - 9.89 ~~11.59~~/100) x 1,757,157 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,200 ~~1,060~~°F + 460°F) x 10^6)

= 32.9 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

1.5 ~~3.5~~ ppm x (1-9.89 ~~11.59~~/100) x 1,757,157 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,200 ~~1,060~~°F + 460°F) x 10^6)

= 1.88 ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-8A ~~A-8~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,137,685 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr ~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x 1.53 ~~3.06~~ lb H_2SO_4/lb SO_2 x 0.08 ~~0.05~~ (converted)

= 0.398 ~~12.2~~ lb/hr

Tables A-8A, A-9A, A-10A ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/30/92

Emission Calculations, Tables A-8A, A-9A, A-10A

Manufacturer/Model: GE PG7221 FA
Fuel Type: NATURAL GAS
Load: 70%
Ambient Temperature: 97°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1080.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.2×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1080.8 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 9.52×10^{-2} lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: _____ ppm x ________ lb/hr fuel oil + 10^6 = NA lb/hr

WEST 501 F
DISTILLATE OIL
BASE LOAD
27°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS

(From Table A-~~1~~ 17 On Distillate Oil; BASE LOAD
All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 19: (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)
171,970 9,280 1,595.9
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)
1,595.9 18,450 86,498
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM
3,502,180 1,104 33
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (28.~~25~~ x 2,116.8 lb/ft²)

÷ 60(min/hr)
2,351,909
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,502,180 33
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (28.~~25~~ x 2,116.8) ÷ 60
793,995
= ~~851,152~~ scfm

WEST 501 F
DISTILLATE OIL
BASE LOAD
27 °F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,351,909 ~~2,450,287~~ acfm x (205°F + 460°F) ÷ (1104 ~~1,060~~°F + 460°F)

= 1,000,012 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

1,000,012 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 65.5 ~~70.2~~ ft/sec

Table A-20 ~~7~~:

PM emissions in tons per year

39.5 ~~17~~ lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 5.9 ~~2.6~~ ton/yr

SO_2 Emissions--Oil (lb/hr)

86,497.6 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 89.35 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

44.5 ~~42~~ ppm x [20.9 x (1 - 10.6 ~~11.59~~/100) - 11.92 ~~10.96~~] x 2,116.8 lb/ft^2

x 2,351,909 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,104 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ lb/hr
290.1

WEST 501 F
DISTILLATE OIL
BASE LOAD
27 °F

CO Emissions (lb/hr) - See Note C:

52 10.6 2,351,909
~~30~~ ppm x (1 - ~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28
(molecular wgt. of carbon)

1,104
x 60 min/hr + (1,545 x (~~1,060~~°F + 460°F) x 10^6)

160.9
= ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

10.6 10.6 2,351,909
~~3.5~~ ppm x (1-~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16
(molecular wgt. of methane)

1104
x 60 min/hr + (1,545 x (~~1,060~~°F + 460°F) x 10^6)

18.7
= ~~6.56~~ lb/hr

Lead Emissions (lb/hr):

1,595.9 1.42
8.9 lb/10^{12} Btu x ~~1,849.9~~ x 10^6 Btu/hr = ~~1.65~~ x 10^{-2} lb/hr

Table A-3:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

86,498 0.08
~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x ~~0.05~~
(converted)

10.9
= ~~12.2~~ lb/hr

22
Table~~s~~ A-~~4~~ ~~and A-5~~:

EPA emission factor as noted in printout; example for manganese:

1,595.9
~~1,849.9~~ (MMBtu) x 14 lb/10^{12} Btu

2.32
= ~~2.59~~ x 10^{-2} lb/hr

8/26/92
~~7/31/92~~

Emission Calculations, Tables A-21, A-22, A-23

Manufacturer/Model: West 501F
Fuel Type: Distillate Oil
Load: Base
Ambient Temperature: 27°F

Arsenic: 4.2 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 6.7×10^{-3} lb/hr

Beryllium: 2.5 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 3.99×10^{-3} lb/hr

Mercury: 3.0 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 4.79×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 5.19×10^{-2} lb/hr

Nickel: 170 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 2.71×10^{-2} lb/hr

Cadmium: 10.5 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 1.68×10^{-2} lb/hr

Chromium: 47.5 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 7.58×10^{-2} lb/hr

Copper: 280 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 0.447 lb/hr

Vanadium: 69.5 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 0.111 lb/hr

Selenium: 23.42 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 3.74×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 4.44×10^{-4} lb/hr

Formaldehyde: 405 $lb/10^{12}$ Btu x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 0.646 lb/hr

Antimony: 9.4 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 3.49×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 3.12×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 1.45×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x 1595.4 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 1.09 lb/hr

Chlorine: 0.5 ppm x 88142.1 lb/hr fuel oil + 10^6 = 32 4.41×10^{-2} lb/hr

WEST 501F
DISTILLATE OIL
BASE LOAD
72°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS

(From Table A-~~1~~ 19 On Distillate Oil; BASE LOAD

All Other Calculations on Spreadsheet are Identical.)

<u>Table A-~~1~~ 19</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)

162,330 9,560 1,551.9
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,551.9 18,450 84,112.5
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

3,509,380 1,104 17
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (28.~~25~~ x 2,116.8 lb/ft^2)

÷ 60(min/hr)

2,370,209
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,509,380 17
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (28.~~25~~ x 2,116.8) ÷ 60

800,173
= ~~851,152~~ scfm

WEST 501 F
DISTILLATE OIL
BASE LOAD
72 °F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 2,370,209 acfm x (205°F + 460°F) + (~~1,060~~ 1,104°F + 460°F)

= ~~1,072,001~~ 1,007,794 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

~~1,072,001~~ 1,007,794 ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= ~~70.2~~ 66.0 ft/sec

<u>Table A-~~2~~ 20</u>:

PM emissions in tons per year

~~17~~ 39 lb/hr x 300 hr/yr + 2,000 lb/ton

= ~~2.6~~ 5.9 ton/yr

SO_2 Emissions--Oil (lb/hr)

~~99,722.9~~ 84,112.5 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= ~~99.72~~ 86.22 lb/hr

NO_x Emissions (lb/hr) - See Note B:

~~42~~ 42.7 ppm x [20.9 x (1 - 11.~~59~~ 91/100) - ~~10.96~~ 11.88] x 2,116.8 lb/ft^2

x ~~2,450,287~~ 2,370,209 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~ 1,104°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 270.9 lb/hr

WEST 501 F
DISTILLATE OIL
BASE LOAD
72°F

CO Emissions (lb/hr) - See Note C:

51.6 ~~30~~ ppm x (1 - 11.91 ~~59~~/100) x 2,370,290 ~~2,450,287~~ acfm x 2,116.8 lb/ft² x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (1,104 ~~1,060~~°F + 460°F) x 10⁶)

= 158.4 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

10.5 ~~3.5~~ ppm x (1-11.91 ~~59~~/100) x 2,370,209 ~~2,450,287~~ acfm x 2,116.8 lb/ft² x 16 (molecular wgt. of methane)

x 60 min/hr + (1,545 x (1,104 ~~1,060~~°F + 460°F) x 10⁶)

= 18.44 ~~6.56~~ lb/hr

Lead Emissions (lb/hr):

8.9 lb/10¹² Btu x 1,557.9 ~~1,849.9~~ x 10⁶ Btu/hr = 1.38 ~~1.65~~ x 10⁻² lb/hr

Table A-21 ~~A-3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

84,112.5 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.08 ~~0.05~~ (converted)

= 10.6 ~~12.2~~ lb/hr

Table A-22 ~~Tables A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

1,551.9 ~~1,849.9~~ (MMBtu) x 14 lb/10¹² Btu

= 2.17 ~~2.59~~ x 10⁻² lb/hr

~~7/31/92~~
8/26/92

Emission Calculations, Tables A-21, A-22, A-23

Manufacturer/Model: West. 501F
Fuel Type: Distillate Oil
Load: Base
Ambient Temperature: 72°F

Arsenic: 4.2 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~[illegible]~~ 6.52 $\times 10^{-3}$ lb/hr

Beryllium: 2.5 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.88 $\times 10^{-3}$ lb/hr

Mercury: 3.0 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 4.66 $\times 10^{-3}$ lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= 5.05 $\times 10^{-2}$ lb/hr

Nickel: 170 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.264 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~[illegible]~~ 1.63 $\times 10^{-2}$ lb/hr

Chromium: 47.5 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~[illegible]~~ 7.37 $\times 10^{-2}$ lb/hr

Copper: 280 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.435 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.108 lb/hr

Selenium: 23.42 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~[illegible]~~ 3.63 $\times 10^{-2}$ lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= 4.31 $\times 10^{-4}$ lb/hr

Formaldehyde: 405 lb/10^{12} Btu x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.629 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= 3.39 $\times 10^{-2}$ lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= ~~[illegible]~~ 3.03 $\times 10^{-2}$ lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= ~~[illegible]~~ 1.41 $\times 10^{-2}$ lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~15[illegible]~~ 51.9 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= 1.06 lb/hr

Chlorine: 0.5 ppm x 84,887.5 lb/hr fuel oil ÷ 10^6 = ~~[illegible]~~ 4.21 $\times 10^{-2}$ lb/hr

WEST 501 F
DISTILLATE OIL
BASE LOAD
97 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97 °F CONDITIONS

(From Table A-~~1~~ 19 On Distillate Oil; BASE LOAD

All Other Calculations on Spreadsheet are Identical.)

<u>Table A-~~1~~ 19</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)

~~183,700~~ 147,180 x ~~10,070~~ 9,850/10^6 = ~~1,849.9~~ 1,449.7 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,449.7 x 10^6 ÷ ~~18,550~~ 18,450 = ~~99,723~~ 78,576 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,311,800 lb/hr x 1,545 x (~~1,060~~ 1,121 °F + 460°F) ÷ (~~28.25~~ 28.09 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 2,267,804 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of

68°F

~~3,743,000~~ 3,311,800 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.09 x 2,116.8) ÷ 60

= ~~851,152~~ 757,369 scfm

WEST 501 F
DISTILLATE OIL
BASE LOAD
97°F

BEST AVAILABLE COPY

12018C2/APPA-2
~~06/13/92~~
8/26/92

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,267,804 $\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad$ 1,121
~~2,450,287~~ acfm x (205°F + 460°F) + (~~1,060~~°F + 460°F)

953,883
= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

953,883
~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

62.5
= ~~70.2~~ ft/sec

20
Table A-~~7~~:

PM emissions in tons per year

36.7
~~17~~ lb/hr x 300 hr/yr + 2,000 lb/ton

5.5
= ~~2.6~~ ton/yr

SO_2 Emissions--Oil (lb/hr)

78,576
~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

81.33
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

42.7 $\qquad\qquad\qquad\qquad\qquad$ 12.57 $\qquad\qquad$ 11.83
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2
x ~~2,450,287~~ ft^3/min
2,267,804
$\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad$ 1,121
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

~~[illegible]~~
= ~~326.2~~ lb/hr
252.9

WEST 501 F
DISTILLATE OIL
BASE LOAD
97 °F

12018C2/APPA-3
~~06/12/92~~
8/26/92

CO Emissions (lb/hr) - See Note C:

51.5 ~~30~~ ppm x (1 - 12.57 ~~11.59~~/100) x 2,267,804 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28
(molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,121 ~~1,060~~°F + 460°F) x 10^6)

= 148.7 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

10.5 ~~3.5~~ ppm x (1 - 12.57 ~~11.59~~/100) x 2,267,804 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16
(molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,121 ~~1,060~~°F + 460°F) x 10^6)

= 17.32 ~~6.56~~ lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x 1,449.7 ~~1,849.9~~ x 10^6 Btu/hr = 1.29 ~~1.65~~ x 10^{-2} lb/hr

Table A-21 ~~3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

78,576 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.08 ~~0.05~~
(converted)

= 9.96 ~~12.2~~ lb/hr

Table~~s~~ A-22 ~~4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

1,449.7 ~~1,849.9~~ (MMBtu) x 14 lb/10^{12} Btu

= 2.03 ~~2.59~~ x 10^{-2} lb/hr

~~7/31/92~~
8/26/92

Emission Calculations, Tables A-21, A-22, A-23

Manufacturer/Model: West. 501F
Fuel Type: Distillate Oil
Load: Base
Ambient Temperature: 97°F

Arsenic: 4.2 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~6.02~~ 6.09 $\times 10^{-3}$ lb/hr

Beryllium: 2.5 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~3.59~~ 3.62 $\times 10^{-3}$ lb/hr

Mercury: 3.0 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~4.3~~ 4.35 $\times 10^{-3}$ lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= ~~4.67~~ 4.72 $\times 10^{-2}$ lb/hr

Nickel: 170 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.24~~4~~6 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.52 $\times 10^{-2}$ lb/hr

Chromium: 47.5 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 6.89 $\times 10^{-2}$ lb/hr

Copper: 280 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.40~~2~~6 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~9.97 $\times 10^{-2}$~~ 1.01 $\times 10^{-1}$ lb/hr

Selenium: 23.42 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = ~~3.36~~ 3.40 $\times 10^{-2}$ lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= ~~3.99~~ 4.03 $\times 10^{-4}$ lb/hr

Formaldehyde: 405 lb/10^{12} Btu x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.587 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= 3.1~~3~~7 $\times 10^{-2}$ lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= 2.8~~0~~3 $\times 10^{-2}$ lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= 1.3 $\times 10^{-2}$ lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x ~~1434.4~~ 1449.7 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= ~~0.98~~ 0.991 lb/hr

Chlorine: 0.5 ppm x ~~79,247.4~~ 78,575.8 lb/hr fuel oil ÷ 10^6 = 3.9~~6~~3 $\times 10^{-2}$ lb/hr

WEST. 501F
Natural Gas
Base LOAD
27°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS
(From Table A-~~X~~ 24 On ~~Distillate Oil~~ Natural Gas; Base LOAD
All Other Calculations on Spreadsheet are Identical.)

Table A-~~X~~ 24: (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)

169,210 9,490 1,605.8
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Natural Gas
~~Fuel Oil~~ (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,605.8 20,900 76,832.7
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

3,702,540 1,063 28.49
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (~~28.25~~ x 2,116.8 lb/ft²)

÷ 60(min/hr)

2,407,465
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,702,540 28.49
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ x 2,116.8) ÷ 60

834,630
= ~~851,152~~ scfm

WEST. 501F
Natural GAS
Base LOAD
27°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,407,465 (~~2,450,287~~) acfm x (205°F + 460°F) + (1,063 (~~1,060~~)°F + 460°F)

= 1,051,191 (~~1,072,001~~) acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

1,051,191 (~~1,072,001~~) ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 68.8 (~~70.2~~) ft/sec

<u>Table A-25 (~~2~~):</u>

PM emissions in tons per year

6.6 (~~17~~) lb/hr x 8460 (~~300~~) hr/yr + 2,000 lb/ton

= 27.92 (~~2.6~~) ton/yr

SO_2 Emissions--Nat. Gas (~~Oil~~) (lb/hr)

1,690,319 cf/hr (~~99,722.9 lb/hr~~) x 1 gr/100 cf (~~0.0005 lb S/lb~~) x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 4.83 (~~99.72~~) lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.5 (~~42~~) ppm x [20.9 x (1 - 7.26 (~~11.59~~)/100) - 13.08 (~~10.96~~)] x 2,116.8 lb/ft^2

x 2,407,465 (~~2,450,287~~) ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (1,063 (~~1,060~~)°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 162.8 (~~326.2~~) lb/hr

WEST. 501F
Natural Gas
Base Load
27°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 10.3 ppm x (1 - ~~11.59~~ 7.26/100) x ~~2,450,287~~ 2,407,465 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,063°F + 460°F) x 10^6)

= ~~98.4~~ 34.8 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.2 ppm x (1-~~11.59~~ 7.26/100) x ~~2,450,287~~ 2,407,465 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,063°F + 460°F) x 10^6)

= ~~6.56~~ 8.10 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table A-~~5~~ 26:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,690,319 cf/hr x 1.0 gr/100cf x 2.0 lb SO_2/lbS x 1.0 lb/7000gr

~~99,722.9 lb/hr~~ x 0.0005 lb S/lb x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.623 lb/hr

Tables ~~A-4 and A-5~~ A-26, A-27, A-28:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

7/31/92

Emission Calculations, Tables A-26, A-27, A-28

Manufacturer/Model: West. 501F
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 27°F

Arsenic: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: ______ lb/10^{12} Btu x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1605.8 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.79×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1605.8 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.142 lb/hr

Antimony: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: ______ pg/J x 2.324 lb/10^{12} Btu/pg/J x ______ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: ______ ppm x ________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

WEST. 501F
Natural Gas
Base LOAD
72°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS

(From Table A-~~1~~ 24 On ~~Distillate Oil~~ Natural Gas; Base LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 24: (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)

~~183,700~~ 143,450 x ~~10,070~~ 10,000/10^6 = ~~1,849.9~~ 1,434.5 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,434.5 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,723~~ 68,636.4 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,369,010 lb/hr x 1,545 x (~~1,060~~ 1,092°F + 460°F) ÷ (~~28.25~~ 28.32 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 2,246,146 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,369,010 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.32 x 2,116.8) ÷ 60

= ~~851,152~~ 764,153 scfm

West. 501F
Natural Gas
Base LOAD
72°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,246,146 ~~2,450,287~~ acfm x (205°F + 460°F) ÷ (1,092 ~~1,060~~°F + 460°F)

= 962,427 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

962,427 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 63.0 ~~70.2~~ ft/sec

<u>Table A-25 ~~2~~</u>:

PM emissions in tons per year

6.0 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr ÷ 2,000 lb/ton

= 25.38 ~~2.6~~ ton/yr

SO_2 Emissions--Nat. GAS ~~0.1~~ (lb/hr)

1,510,800 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x1.0 lb/7000 gr

= 4.31 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.4 ~~42~~ ppm x [20.9 x (1 - 8.82 ~~11.59~~/100) - 12.91 ~~10.96~~] x 2,116.8 lb/ft^2

x 2,246,146 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,092 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 144.8 ~~326.2~~ lb/hr

WEST. 501F
Natural Gas
Base LOAD
72°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 10.3 ppm x (1 - ~~11.59~~ 8.82/100) x ~~2,450,287~~ 2,246,146 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,092°F + 460°F) x 10^6)

= ~~98.4~~ 31.3 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.1 ppm x (1-~~11.59~~ 8.82/100) x ~~2,450,287~~ 2,246,146 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,092°F + 460°F) x 10^6)

= ~~6.56~~ 7.12 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-~~3~~26:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,510,000 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr ~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.556 lb/hr

Tables ~~A-4 and A-5~~ A-26, A-27, A-28:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

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Emission Calculations, Tables A-26, A-27, A-28

Manufacturer/Model: West. 501F
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 72°F

Arsenic: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Nickel: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: ____ $lb/10^{12}$ Btu x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x 1434.5 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 1.60×10^{-3} lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x 1434.5 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 0.126 lb/hr

Antimony: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Barium: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cobalt: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Zinc: ____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chlorine: ____ ppm x ____ lb/hr fuel oil + 10^6 = NA lb/hr

West 501F
Natural Gas
Base LOAD
79°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 79°F CONDITIONS

(From Table A-~~1~~ 24 On ~~Distillate Oil~~ Natural Gas; Base LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 24: (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)

~~103,700~~ 139500 x ~~10,070~~ 10,100/10^6 = ~~1,849.9~~ 1,409.0 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,409.0 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,725~~ 67,413.9 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,311,770 lb/hr x 1,545 x (~~1,060~~ 1,098°F + 460°F) ÷ (~~28.25~~ 28.26 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 2,221,160 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,311,770 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.26 x 2,116.8) ÷ 60

= ~~851,152~~ 752,742 scfm

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West. 501F
Natural Gas
Base LOAD
79°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,221,160 ~~2,450,287~~ acfm x (205°F + 460°F) ÷ (1,098 ~~1,060~~°F + 460°F)

= 948,056 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

948,056 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 62.1 ~~70.2~~ ft/sec

<u>Table A-25 ~~2~~:</u>

PM emissions in tons per year

5.9 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr ÷ 2,000 lb/ton

= 24.96 ~~2.6~~ ton/yr

SO_2 Emissions--Oil (lb/hr)

1,483,105 cf/hr ~~99,722.9 lb/hr~~ x 1.0gr/100cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.016/7000 gr

= 4.24 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.5 ~~42~~ ppm x [20.9 x (1 - 9.32 ~~11.59~~/100) - 12.82 ~~10.96~~] x 2,116.8 lb/ft^2

x 2,221,160 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1098 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 142.9 ~~326.2~~ lb/hr

West 501F
Natural Gas
Base Load
79°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 10.4 ppm x (1 - ~~11.59~~ 9.32/100) x ~~2,450,287~~ 2,221,160 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,098°F + 460°F) x 10^6)

= ~~98.4~~ 30.9 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.1 ppm x (1-~~11.59~~ 9.32/100) x ~~2,450,287~~ 2,221,160 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,098°F + 460°F) x 10^6)

= ~~6.56~~ 6.97 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table A-~~5~~ 26:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,483,105 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/1 lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.546 lb/hr

Tables ~~A-4 and A-5~~ A-26, A-27, A-28:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

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Emission Calculations, Tables A-26, A-27, A-28

Manufacturer/Model: West 501F
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 79°F

Arsenic: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Nickel: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x ~~[illegible]~~ 1,409.0 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = $1.5\cancel{6}7 \times 10^{-3}$ lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x ~~[illegible]~~ 1,409.0 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = $0.12\cancel{3}4$ lb/hr

Antimony: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Barium: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cobalt: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Zinc: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chlorine: ______ ppm x ________ lb/hr fuel oil + 10^6 = NA lb/hr

West 501F
Natural Gas
Base Load
97°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~57~~ 97°F CONDITIONS

(From Table A-~~5~~ 24 On ~~Distillate Oil~~ Natural Gas; Base Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~5~~ 24: (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)

~~183,700~~ 129,370 x ~~10,070~~ 10,360/10^6 = ~~1,849.9~~ 1,340.3 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,340.3 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,725~~ 64,127.9 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 3,180,510 lb/hr x 1,545 x (~~1,060~~ 1,111°F + 460°F) ÷ (~~28.25~~ 28.23 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 2,152,966 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 3,180,510 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.23 x 2,116.8) ÷ 60

= ~~851,152~~ 723,594 scfm

West. 501F
Natural Gas
Base LOAD
97°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,152,966
~~2,450,287~~ acfm x (205°F + 460°F) + (~~1,060~~ 1,111 °F + 460°F)

911,345
= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

911,345
~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

59.7
= ~~70.2~~ ft/sec

Table A-~~4~~ 25:

PM emissions in tons per year

5.7 8460
~~17~~ lb/hr x ~~300~~ hr/yr + 2,000 lb/ton

24.11
= ~~2.6~~ ton/yr

SO_2 Emissions--~~Oil~~ Nat. Gas (lb/hr)

1,410,814 cf/hr 1.0 gr/100 cf
~~99,722.9 lb/hr~~ x ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

4.03
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

255 9.56 12.84
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2

x ~~2,450,287~~ 2,152,966 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~ 1,111 °F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

135.8
= ~~326.2~~ lb/hr

WEST 501F
Natural Gas
Base Load
97°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 10.2 ppm x (1 - ~~11.59~~ 9.56/100) x ~~2,450,287~~ 2,152,966 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,111°F + 460°F) x 10^6)

= ~~98.4~~ 29.1 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.3 ppm x (1-~~11.59~~ 9.56/100) x ~~2,450,287~~ 2,152,966 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,111°F + 460°F) x 10^6)

= ~~6.56~~ 7.01 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

<u>Table A-~~5~~ 26</u>:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,410,814 cf/hr x 1.0 gr/100cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.520 lb/hr

<u>Tables ~~A-4 and A-5.~~</u> A-26, A-27, A-28:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

Emission Calculations, Tables A-26, A-27, A-28

Manufacturer/Model: WEST. 501F
Fuel Type: Natural Gas
Load: Base
Ambient Temperature: 97°F

Arsenic: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Nickel: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: _____ $lb/10^{12}$ Btu x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x 1340.3 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu

= 1.49×10^{-3} lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x 1340.3 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 0.118 lb/hr

Antimony: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Barium: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Cobalt: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Zinc: _____ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x _____ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Chlorine: _____ ppm x _______ lb/hr fuel oil + 10^6 = NA lb/hr

WEST 501 F
DISTILLATE OIL
70% LOAD
27 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS

(From Table A-~~1~~ 19A On Distillate Oil; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 19A: (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)

~~183,700~~ 133,020 x ~~10,070~~ 9,770/10^6 = ~~1,849.9~~ 1,299.6 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,299.6 x 10^6 ÷ ~~18,550~~ 18,450 = ~~99,723~~ 70,439.3 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,934,960 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.34 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 2,003,120 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,934,960 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.34 x 2,116.8) ÷ 60

= ~~851,152~~ 831,484 scfm

WEST 501 F
DISTILLATE OIL
70% LOAD
270°F

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Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,003,120 ~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) ÷ (1,130 ~~1,060~~°F + 460°F)

= 831,484 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

831,484 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 54.5 ~~70.2~~ ft/sec

<u>Table A-20A ~~2~~:</u>

PM emissions in tons per year

32.6 ~~17~~ lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 4.9 ~~2.6~~ ton/yr

SO_2 Emissions--Oil (lb/hr)

70,439.3 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 72.69 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

42.5 ~~42~~ ppm x [20.9 x (1 - 10.43 ~~11.59~~/100) - 12.08 ~~10.96~~] x 2,116.8 lb/ft^2

x 2,003,120 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,130 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 227.9 ~~326.2~~ lb/hr

WEST 501 F
DISTILLATE OIL
70 % LOAD
27 °F

CO Emissions (lb/hr) - See Note C:

51.5 10.43 2,003,120
~~30~~ ppm x (1 - ~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

1,130
x 60 min/hr + (1,545 x (~~1,060~~°F + 460°F) x 10^6)

133.8
= ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

10.0 10.43 2,003,120
~~3.5~~ ppm x (1-~~11.59~~/100) x ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

1,130
x 60 min/hr + (1,545 x (~~1,060~~°F + 460°F) x 10^6)

14.84
= ~~6.56~~ lb/hr

Lead Emissions (lb/hr):

1,299.6 1.16
8.9 lb/10^{12} Btu x ~~1,849.9~~ x 10^6 Btu/hr = ~~1.65~~ x 10^{-2} lb/hr

21A
Table A-~~3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

70,439.3 8
~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.0~~5~~ (converted)

8.90
= ~~12.2~~ lb/hr

22A
Table~~s~~ A-~~4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

1,299.6
~~1,849.9~~ (MMBtu) x 14 lb/10^{12} Btu

1.82
= ~~2.59~~ x 10^{-2} lb/hr

~~7/31/92~~
8/26/92

Emission Calculations, Tables A-21A, A-22A, A-23A

Manufacturer/Model: WEST. 501F
Fuel Type: Distillate Oil
Load: 70%
Ambient Temperature: 27°F

Arsenic: 4.2 lb/10^{12} Btu x 1299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 5.46 x 10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 1299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.25 x 10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 1299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.90 x 10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 4.23 x 10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.221 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.36 x 10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 6.17 x 10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.364 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 9.03 x 10^{-2} lb/hr

Selenium: 23.42 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.04 x 10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 3.61 x 10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.526 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 2.84 x 10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 2.54 x 10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.18 x 10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1,299.6 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.888 lb/hr

Chlorine: 0.5 ppm x 70,439.3 lb/hr fuel oil + 10^6 = 3.52 x 10^{-2} lb/hr

WEST 501 F
DISTILLATE OIL
70% LOAD
72 °F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72 °F CONDITIONS

(From Table A-~~1~~ 19A On Distillate Oil; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 19A: (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)

113,400 10,310 1,169.2
~~183,700~~ x ~~10,070~~/10^6 = ~~1,849.9~~ x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,169.2 18,450 63,368.8
~~1,849.9~~ x 10^6 ÷ ~~18,550~~ = ~~99,723~~ lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

2,757,580 1,130 28.19
~~3,743,000~~ lb/hr x 1,545 x (~~1,060~~°F + 460°F) ÷ (~~28.25~~ x 2,116.8 lb/ft²)

÷ 60(min/hr)

1,892,217
= ~~2,450,287~~ acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

2,757,580 28.19
~~3,743,000~~ lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ x 2,116.8) ÷ 60

628,359
= ~~851,152~~ scfm

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WEST 501 F
DISTILLATE OIL
70% LOAD
72°F

12018C2/APPA-2
~~06/13/92~~
8/26/92

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,892,217
~~2,757,500~~
~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) + (1,130 ~~1,060~~°F + 460°F)

= 785,449 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

785,449 ~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 51.4 ~~70.2~~ ft/sec

<u>Table A-20A ~~2~~</u>:

PM emissions in tons per year

30 ~~17~~ lb/hr x 300 hr/yr + 2,000 lb/ton

= 4.5 ~~2.6~~ ton/yr

SO_2 Emissions--Oil (lb/hr)

63,368.8 ~~99,722.9~~ lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 65.65 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

42.5 ~~42~~ ppm x [20.9 x (1 - 11.58 ~~11.59~~/100) - 12.17 ~~10.96~~] x 2,116.8 lb/ft^2
x 2,450,287 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (1,130 ~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= 204.5 ~~326.2~~ lb/hr

WEST 501F
DISTILLATE OIL
70% LOAD
72°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 51.5 ppm x (1 - ~~11.59~~ 11.58/100) x ~~2,450,287~~ 1,892,217 acfm x 2,116.8 lb/ft² x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10⁶)

= ~~98.4~~ 124.7 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 10.1 ppm x (1-~~11.59~~ 11.58/100) x ~~2,450,287~~ 1,892,217 acfm x 2,116.8 lb/ft² x 16 (molecular wgt. of methane)

x 60 min/hr + (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10⁶)

= ~~6.56~~ 13.98 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10¹² Btu x ~~1,849.9~~ 1,169.2 x 10⁶ Btu/hr = ~~1.65~~ 1.04 x 10⁻² lb/hr

<u>Table A-~~3~~ 21A</u>:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

~~99,722.9~~ 63,368.8 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.0~~5~~8 (converted)

= ~~12.2~~ 8.04 lb/hr

<u>Table~~s~~ A-~~4 and A-5~~ 22A</u>:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9~~ 1,169.2 (MMBtu) x 14 lb/10¹² Btu

= ~~2.59~~ 1.64 x 10⁻² lb/hr

~~7/31/92~~
8/26/92

Emission Calculations, Tables A-21A, A-22A, A-23A

Manufacturer/Model: West 501F
Fuel Type: Distillate Oil
Load: 70%
Ambient Temperature: 72°F

Arsenic: 4.2 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 4.91×10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.92×10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.51×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.80×10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.199 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.23×10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 5.55×10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.327 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 8.13×10^{-2} lb/hr

Selenium: 23.42 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.74×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.25×10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.474 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.55×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.28×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.06×10^{-2} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 69.2 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.799 lb/hr

Chlorine: 0.5 ppm x 63,368.8 lb/hr fuel oil ÷ 10^6 = 3.17×10^{-2} lb/hr

WEST 501 F
DISTILLATE OIL
70% LOAD
97 °F

12018C2/APPA-1
~~06/13/92~~
8/26/92

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97°F CONDITIONS

(From Table A-~~1~~ 19A On Distillate Oil; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 19A: (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)

~~183,700~~ 102,810 x ~~10,070~~ 10,680/10^6 = ~~1,849.9~~ 1,098 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,098 x 10^6 ÷ ~~18,550~~ 18,450 = ~~99,723~~ 59,512.8 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,662,180 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.12 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 1,831,107 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of

68°F

~~3,743,000~~ 2,662,180 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.12 x 2,116.8) ÷ 60

= ~~851,152~~ 608,066 scfm

WEST 501 F
DISTILLATE OIL
70% LOAD
97 °F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 1,831,107 acfm x (~~205~~ 200°F + 460°F) + (~~1,060~~ 1,130°F + 460°F)

= ~~1,072,001~~ 760,082 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

~~1,072,001~~ 760,082 ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= ~~70.2~~ 49.8 ft/sec

<u>Table A-~~2~~ 20A</u>:

PM emissions in tons per year

~~17~~ 28.5 lb/hr x 300 hr/yr + 2,000 lb/ton

= ~~2.6~~ 4.3 ton/yr

SO_2 Emissions--Oil (lb/hr)

~~99,722.9~~ 59,512.8 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= ~~99.72~~ 61.77 lb/hr

NO_x Emissions (lb/hr) - See Note B:

~~42~~ 42.7 ppm x [20.9 x (1 - ~~11.59~~ 12.09/100) - ~~10.96~~ 12.26] x 2,116.8 lb/ft^2
x ~~2,450,287~~ 1,831,107 ft^3/min
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~ 1,130°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 192.7 lb/hr

WEST 501 F
DISTILLATE OIL
70% LOAD
97 °F

CO Emissions (lb/hr) - See Note C:

~~30~~ 51.5 ppm x (1 - ~~11.59~~ 12.09/100) x ~~2,450,287~~ 1,831,107 acfm x 2,116.8 lb/ft^2 x 28
(molecular wgt. of carbon)

x 60 min/hr + (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~98.4~~ 120.0 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 10.5 ppm x (1-~~11.59~~ 12.09/100) x ~~2,450,287~~ 1,831,107 acfm x 2,116.8 lb/ft^2 x 16
(molecular wgt. of methane)

x 60 min/hr + (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~6.56~~ 13.98 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x ~~1,849.9~~ 1098 x 10^6 Btu/hr = ~~1.65~~ 9.77 x 10$^{-\cancel{2}\,3}$ lb/hr

Table A-~~3~~ 21A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

~~99,722.9~~ 59,512.8 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.0~~5~~8
(converted)

= ~~12.2~~ 7.57 lb/hr

Table~~s~~ A-~~4~~ 22A ~~and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9~~ 1098 (MMBtu) x 14 lb/10^{12} Btu

= ~~2.59~~ 1.54 x 10^{-2} lb/hr

7/31/92

Emission Calculations, Tables A-21A, A-22A, A-23A

Manufacturer/Model: West. 501F
Fuel Type: Distillate Oil
Load: 70%
Ambient Temperature: 97°F

Arsenic: 4.2 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 4.61×10^{-3} lb/hr

Beryllium: 2.5 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.75×10^{-3} lb/hr

Mercury: 3.0 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.29×10^{-3} lb/hr

Fluoride: 14.0 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.57×10^{-2} lb/hr

Nickel: 170 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.187 lb/hr

Cadmium: 10.5 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 1.15×10^{-2} lb/hr

Chromium: 47.5 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 5.22×10^{-2} lb/hr

Copper: 280 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.307 lb/hr

Vanadium: 69.5 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 7.63×10^{-2} lb/hr

Selenium: 23.42 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.57×10^{-2} lb/hr

Polycyclic Organic Matter: 0.278 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 3.05×10^{-4} lb/hr

Formaldehyde: 405 lb/10^{12} Btu x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.445 lb/hr

Antimony: 9.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.40×10^{-2} lb/hr

Barium: 8.4 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 2.14×10^{-2} lb/hr

Cobalt: 3.9 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 9.95×10^{-3} lb/hr

Zinc: 294 pg/J x 2.324 lb/10^{12} Btu/pg/J x 1098 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.750 lb/hr

Chlorine: 0.5 ppm x 59,512.8 lb/hr fuel oil ÷ 10^6 = 2.98×10^{-2} lb/hr

West. 501F
Natural Gas
70% LOAD
27°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 27°F CONDITIONS

(From Table A-~~9~~ 24A On ~~Distillate Oil~~ Natural Gas; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~9~~ 24A: (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)

~~183,700~~ 118,330 x ~~10,070~~ 10,490/10^6 = ~~1,849.9~~ 1,241.3 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,241.3 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,723~~ 59,395 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,754,000 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.49 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,869,744 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,754,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.49 x 2,116.8) ÷ 60

= ~~851,152~~ 620,896 scfm

West. 501F
Natural Gas
70% LOAD
27°F

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Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,869,744 ~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) + (1,130 ~~1,060~~°F + 460°F)

= 776,120 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

776,120 ~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 50.8 ~~70.2~~ ft/sec

Table A-25A ~~2~~:

PM emissions in tons per year

4.9 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr + 2,000 lb/ton

= 20.73 ~~2.6~~ ton/yr

SO_2 Emissions--GAS ~~Oil~~ (lb/hr)

1,306,612 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 3.73 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.4 ~~42~~ ppm x [20.9 x (1 - 7.30 ~~11.59~~/100) - 13.04 ~~10.96~~] x 2,116.8 lb/ft^2

x 1,869,744 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (1,130 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 121.3 ~~326.2~~ lb/hr

West 501F
Natural Gas
70% LOAD
27°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 10.4 ppm x (1 - ~~11.59~~ 7.3/100) x ~~2,450,287~~ 1,869,744 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~98.4~~ 26.1 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.5~~ 4.2 ppm x (1-~~11.59~~ 7.3/100) x ~~2,450,287~~ 1,869,744 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~6.56~~ 6.02 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table A-~~3~~ 26A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,306,612 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.481 lb/hr

Tables ~~A-4 and A-5~~ A-26A, A-27A, A-28A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

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Emission Calculations, Tables A-26A, A-27A, A-28A

Manufacturer/Model: West. 501F
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 27°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x ~~[illegible]~~ 1241.3 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.38×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x ~~[illegible]~~ 1241.3 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 0.109 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: _____ ppm x _________ lb/hr fuel oil + 10^6 = NA lb/hr

West 501F
Natural Gas
70% Load
64°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 64°F CONDITIONS

(From Table A-~~1~~ 24A On ~~Distillate Oil~~ Natural Gas; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 24A: (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)

~~183,700~~ 103,390 x ~~10,070~~ 11,020/10^6 = ~~1,849.9~~ 1,139.4 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,139.4 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,723~~ 54,514.7 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,678,720 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.36 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 1,826,635 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,678,720 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.36 x 2,116.8) ÷ 60

= ~~851,152~~ 606,581 scfm

West 501F
Natural Gas
70% Load
64°F

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12018C2/APPA-
~~06/13/9~~
8/26/9

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,826,635 acfm x (200°F + 460°F) ÷ (1,130°F + 460°F)
~~2,450,287~~ acfm x (~~205~~°F + 460°F) ÷ (~~1,060~~°F + 460°F)

= 758,226 acfm
= 1~~,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

758,226
~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 49.7
= ~~70.2~~ ft/sec

Table A-25A
Table A-~~5~~:

PM emissions in tons per year

4.8 lb/hr x 8460 hr/yr ÷ 2,000 lb/ton
~~17~~ lb/hr x ~~300~~ hr/yr ÷ 2,000 lb/ton

= 20.30
= ~~2.6~~ ton/yr

SO_2 Emissions--Gas (lb/hr)
SO_2 Emissions--~~Oil~~ (lb/hr)

1,199,324 cf/hr x 1.0 gr/100 cf
~~99,722.9 lb/hr~~ x ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb / 7000 gr

= 3.43
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.4 ppm x [20.9 x (1 - 8.32/100) - 13.1] x 2,116.8 lb/ft^2
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2
x ~~2,450,287~~ ft^3/min
1,826,635
x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~ 1,130°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= 113.4
= ~~326.2~~ lb/hr

West. 501F
Natural Gas
70% Load
64°F

CO Emissions (lb/hr) - See Note C:

10.3 ~~30~~ ppm x (1 - 8.32 ~~11.59~~/100) x 1,826,635 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,130 ~~1,060~~°F + 460°F) x 10^6)

= 25.0 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

4.3 ~~3.5~~ ppm x (1-8.32 ~~11.59~~/100) x 1,826,635 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,130 ~~1,060~~°F + 460°F) x 10^6)

= 5.96 ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-26A ~~5~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,199,324 cf/hr x 1.0 gr /100 cf x 2 lb SO_2 /lb S x 1.0 lb/7000 gr

99,722.9 lb/hr x 0.0005 lb S/lb x 1.53 ~~3.06~~ lb H_2SO_4/lb SO_2 x 0.08 ~~0.05~~ (converted)

= 0.442 ~~12.2~~ lb/hr

Tables A-26A, A-27A, A-28A ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

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Emission Calculations, Tables A-26A, A-27A, A-28A

Manufacturer/Model: West. 501F
Fuel Type: NATURAL GAS
Load: 70%
Ambient Temperature: 64°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x ~~[illegible]~~ 1139.4 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= 1.27×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x ~~[illegible]~~ 1139.4 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 0.10 lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Chlorine: _____ ppm x ________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

West 501F
Nat Gas
70% Load
72°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 72°F CONDITIONS

(From Table A-~~1~~ 24A On ~~Distillate Oil;~~ Nat Gas 70% Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 24A: (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)

~~103,700~~ 100,210 x ~~10,070~~ 11,150/10^6 = ~~1,849.9~~ 1,117.3 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,117.3 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,723~~ 53,461.3 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,647,790 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.33 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,807,837 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,647,790 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.33 x 2,116.8) ÷ 60

= ~~851,152~~ 600,338 scfm

West 501F
Nat Gas
70% Load
72°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,807,837 200 1,130
~~2,450,287~~ acfm x (~~205~~°F + 460°F) + (~~1,060~~°F + 460°F)
750,423
= ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

750,423
~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)
49.1
= ~~70.2~~ ft/sec

25A
Table A-~~8~~:

PM emissions in tons per year

4.7 8460
~~17~~ lb/hr x ~~300~~ hr/yr + 2,000 lb/ton
19.88
= ~~2.6~~ ton/yr

GAS
SO_2 Emissions--~~Oil~~ (lb/hr)

1,176,149 cf/hr 1.0gr/100cf
~~99,722.9 lb/hr~~ x ~~0.0005 lb S/~~lb x 2 lb SO_2/lb S x1.0 lb/~~S~~ /7000 gr
336
= ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.4 8.68 13.08
~~42~~ ppm x [20.9 x (1 - ~~11.59~~/100) - ~~10.96~~] x 2,116.8 lb/ft^2
x ~~2,450,287~~ ft^3/min
1,807,837
1,130
x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (~~1,060~~°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]
111.2
= ~~326.2~~ lb/hr

West 501F
Nat. Gas
70% Load
72°F

CO Emissions (lb/hr) - See Note C:

10.4 ~~30~~ ppm x (1 - 8.68 ~~11.59~~/100) x 1,807,837 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 28
(molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,130 ~~1,060~~°F + 460°F) x 10^6)

= 24.9 ~~98.4~~ lb/hr

VOC Emissions (lb/hr) - See Note C:

4.4 ~~3.5~~ ppm x (1-8.68 ~~11.59~~/100) x 1,807,837 ~~2,450,287~~ acfm x 2,116.8 lb/ft^2 x 16
(molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,130 ~~1,060~~°F + 460°F) x 10^6)

= 6.01 ~~6.56~~ lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-26A ~~3~~:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,176,149 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x 1.53 ~~3.06~~ lb H_2SO_4/lb SO_2 x 0.08 ~~0.05~~
(converted)

= 0.433 ~~12.2~~ lb/hr

Tables A-26A, A-27A, A-28A ~~A-4 and A-5~~:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

7/31/92

Emission Calculations, Tables A-26A, A-27A, A-28A

Manufacturer/Model: West. 501F
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 72°F

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 1117.3 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= 1.24×10^{-3} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 1117.3 MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu = 9.85×10^{-2} lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr ÷ 10^6 MMBtu/10^{12} Btu

= NA lb/hr

Chlorine: _____ ppm x _______ lb/hr fuel oil ÷ 10^6 = NA lb/hr

West 501F
Natural Gas
70% Load
79°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~25~~ 79°F CONDITIONS

(From Table A-~~5~~ 24A On ~~Distillate Oil;~~ Natural Gas 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

<u>Table A-~~5~~ 24A</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)

~~183,700~~ 97,490 x ~~10,070~~ 11,270/10^6 = ~~1,849.9~~ 1,098.7 x 10^6 Btu/hr

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,098.7 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,723~~ 52,570 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,619,850 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.27 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= ~~2,450,287~~ 1,792,201 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,619,850 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.27 x 2,116.8) ÷ 60

= ~~851,152~~ 595,146 scfm

West 501F
Natural Gas
70% Load
79°F

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Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

~~2,450,287~~ 1,792,201 acfm x (~~205~~ 200°F + 460°F) ÷ (~~1,060~~ 1,130°F + 460°F)

= ~~1,072,001~~ 743,932 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

~~1,072,001~~ 743,932 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= ~~70.2~~ 48.7 ft/sec

Table A-~~2~~ 25A:

PM emissions in tons per year

~~17~~ 4.7 lb/hr x ~~300~~ 8460 hr/yr ÷ 2,000 lb/ton

= ~~2.6~~ 19.88 ton/yr

SO_2 Emissions--~~Oil~~ GAS (lb/hr)

~~99,722.9 lb/hr~~ 1,156,539 cf/hr x ~~0.0005 lb S/lb~~ 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= ~~99.72~~ 3.30 lb/hr

NO_x Emissions (lb/hr) - See Note B:

~~42~~ 25.4 ppm x [20.9 x (1 - ~~11.59~~ 9.12/100) - ~~10.96~~ 13.04] x 2,116.8 lb/ft^2

x ~~2,450,287~~ 1,792,201 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (~~1,060~~ 1,130°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= ~~326.2~~ 109.3 lb/hr

West 501F
Natural Gas
70% Load
79°F

CO Emissions (lb/hr) - See Note C:

~~90~~ 10.2 ppm x (1 - ~~11.59~~ 9.12/100) x ~~2,450,287~~ 1,792,201 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~98.4~~ 24.1 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~9.5~~ 4.5 ppm x (1-~~11.59~~ 9.12/100) x ~~2,450,287~~ 1,792,201 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~6.56~~ 6.06 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr~~

Table A-~~5~~ 26A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

(1,156,539 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr)

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.426 lb/hr

Tables ~~A-4 and A-5~~ A-26A, A-27A, A-28A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^{12} Btu~~ Not Applicable

~~= 2.59 x 10^{-2} lb/hr~~

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Emission Calculations, Tables A-26A, A-27A, A-28A

Manufacturer/Model: West. 501F
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 79°F

Arsenic: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Nickel: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x ~~[illegible]~~ 1098.7 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= 1.22×10^{-3} lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x ~~[illegible]~~ 1098.7 MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu = 9.68×10^{-2} lb/hr

Antimony: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Barium: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Cobalt: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Zinc: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr ÷ 10^6 $MMBtu/10^{12}$ Btu

= NA lb/hr

Chlorine: ______ ppm x ________ lb/hr fuel oil ÷ 10^6 = NA lb/hr

West 501F
Natural Gas
70% Load
97°F

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27~~ 97°F CONDITIONS

(From Table A-~~1~~ 24A On ~~Distillate Oil~~ Natural Gas; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 24A: (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)

~~103,700~~ 90,340 x ~~10,070~~ 11,600/10^6 = ~~1,849.9~~ 1,047.9 x 10^6 Btu/hr

~~Fuel Oil~~ Nat. Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 1,047.9 x 10^6 ÷ ~~18,550~~ 20,900 = ~~99,723~~ 50,140.9 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 2,554,960 lb/hr x 1,545 x (~~1,060~~ 1,130°F + 460°F) ÷ (~~28.25~~ 28.25 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,749,383 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 2,554,960 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.25 x 2,116.8) ÷ 60

= ~~851,152~~ 580,927 scfm

West 501F
Natural Gas
70% Load
97°F

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,749,383 ~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) ÷ (1,130 ~~1,060~~°F + 460°F)

= 726,159 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

726,159 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 47.6 ~~70.2~~ ft/sec

<u>Table A-25A ~~4~~</u>:

PM emissions in tons per year

4.6 ~~17~~ lb/hr x 8460 ~~300~~ hr/yr ÷ 2,000 lb/ton

= 19.46 ~~2.6~~ ton/yr

SO_2 Emissions--Gas ~~Oil~~ (lb/hr)

1,103,099 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 3.15 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - See Note B:

25.4 ~~42~~ ppm x [20.9 x (1 - 9.29 ~~11.59~~/100) - 13.15 ~~10.96~~] x 2,116.8 lb/ft^2

x 1,749,383 ~~2,450,287~~ ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,130 ~~1,060~~°F + 460°F)

x 5.9 x 10^6 (adjust for ppm)]

= 104.0 ~~326.2~~ lb/hr

West 501F
Natural Gas
70% Load
97°F

CO Emissions (lb/hr) - See Note C:

~~30~~ 10.4 ppm x (1 - ~~11.59~~ 9.29/100) x ~~2,450,287~~ 1,749,383 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~98.4~~ 23.9 lb/hr

VOC Emissions (lb/hr) - See Note C:

~~3.~~5 3.8 ppm x (1-~~11.59~~ 9.29/100) x ~~2,450,287~~ 1,749,383 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr + (1,545 x (~~1,060~~ 1,130°F + 460°F) x 10^6)

= ~~6.56~~ 4.99 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10^12 Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^-2 lb/hr~~

Table A-~~8~~ 26A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

1,103,099 cf/hr x 1.0 gr/100 cf x 2 lb SO_2/lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 0.406 lb/hr

Tables ~~A-4 and A-5~~ A-26A, A-27A, A-28A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10^12 Btu~~ Not Applicable

~~= 2.59 x 10^-2 lb/hr~~

7/31/92

Emission Calculations, Tables A-26A, A-27A, A-28A

Manufacturer/Model: West. 501F
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: 97°F

Arsenic: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Beryllium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Mercury: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Fluoride: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Nickel: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cadmium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chromium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Copper: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Vanadium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Selenium: ______ $lb/10^{12}$ Btu x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 $lb/10^{12}$ Btu x 1047.9 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 1.17×10^{-3} lb/hr

Formaldehyde: 88.12 $lb/10^{12}$ Btu x 1047.9 MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = 9.23×10^{-2} lb/hr

Antimony: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Barium: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Cobalt: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Zinc: ______ pg/J x 2.324 $lb/10^{12}$ Btu/pg/J x ______ MMBtu/hr + 10^6 $MMBtu/10^{12}$ Btu = NA lb/hr

Chlorine: ______ ppm x ________ lb/hr fuel oil + 10^6 = NA lb/hr

Duct Burner - Supplemental Firing
Natural Gas
Base LOAD
All temperatures

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27°F~~ All temperatures given CONDITIONS

(From Table A-~~5~~ 11 On ~~Distillate Oil~~ Natural Gas; Base Load

All Other Calculations on Spreadsheet are Identical.)

Table A-~~5~~ 11: (Note: all other data not calculated but supplied by Manufacturer)

Heat Input (10^6 Btu/hr): 100 mmBtu/hr (given)

~~Power (kW) x Heat Rate (10^6 Btu/kWh)~~

~~183,700 x 10,070/10^6 = 1,849.9 x 10^6 Btu/hr~~

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 100.0 x 10^6 ÷ ~~18,550~~ 23,839 = ~~99,723~~ 4,194.8 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 5,244 lb/hr x 1,545 x (~~1,060~~ 205°F + 460°F) ÷ (~~28.25~~ 28.00 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,515 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 5,244 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.00 x 2,116.8) ÷ 60

= ~~851,152~~ 1,203 scfm

Duct Burner - Supplemental Firing
Natural Gas
Base Load
All temperatures

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,515 ~~2,450,287~~ acfm x (205°F + 460°F) + (205 ~~1,060~~°F + 460°F)

= 1,515 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

1,515 ~~1,072,001~~ ft^3/min + 60 + (18.0^2 + 4 x 3.14159)

= 0.1 ~~70.2~~ ft/sec

<u>Table A-12 ~~2~~</u>:

PM emissions in tons per year

0.01 lb/mmBtu x 100 mmBtu/hr x 8760 hr/yr ~~17 lb/hr x 300 hr/yr~~ + 2,000 lb/ton

= 4.38 ~~2.6~~ ton/yr

SO_2 Emissions--Gas ~~Oil~~ (lb/hr)

105,263 cf/hr ~~99,72219 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 0.30 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) - ~~See Note B~~:

~~42 ppm x [20.9 x (1 - 11.59/100) - 10.96] x 2,116.8 lb/ft²~~
~~x 2,450,287 ft³/min~~

~~x 46 (molecular wgt NO₂) x 60 min/hr + [1,545 x (1,060°F + 460°F)~~
~~x 5.9 x 10⁶ (adjust for ppm)]~~

~~326.2 lb/hr~~

0.10 lb/mmBtu x 100.0 mmBtu/hr = 10.0 lb/hr

Duct Burner - Supplemental Firing
Natural Gas
Base Load
All temperatures

CO Emissions (lb/hr) - ~~See Note C~~:

~~30 ppm x (1 - 11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft² x 28 (molecular wgt. of carbon)~~

~~x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10⁶)~~

~~= 98.4 lb/hr~~

0.10 lb/MMBtu × 100.0 MMBtu/hr = 10 lb/hr

VOC Emissions (lb/hr) - ~~See Note C~~:

~~3.5 ppm x (1-11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft² x 16 (molecular wgt. of methane)~~

~~x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10⁶)~~

~~= 6.56 lb/hr~~ 0.029 lb/MMBtu × 100.0 MMBtu/hr = 2.90 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10¹² Btu x 1,849.9 x 10⁶ Btu/hr = 1.65 x 10⁻² lb/hr~~

Table A-~~5~~ 13:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

105,263 cf/hr × 100 gr/100cf × 2 lb SO_2/lb S × 1.0 lb/7000 gr
~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08
(converted)
= ~~12.2~~ 3.68×10^{-2} lb/hr

Tables ~~A-4 and A-5~~ A-13, A-14:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10¹² Btu~~ Not Applicable

~~= 2.59 x 10⁻² lb/hr~~

Emission Calculations, Tables A-13, A-14

Manufacturer/Model: Duct Burner
Fuel Type: Natural Gas
Load: 100%
Ambient Temperature: All temperatures

Arsenic: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Nickel: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: _____ lb/10^{12} Btu x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 100.0 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 1.11×10^{-4} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 100.0 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 8.81×10^{-3} lb/hr

Antimony: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Barium: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cobalt: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Zinc: _____ pg/J x 2.324 lb/10^{12} Btu/pg/J x _____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chlorine: _____ ppm x ________ lb/hr fuel oil + 10^6 = NA lb/hr

Duct Burner-Supplemental Firing
Natural Gas
70% Load
All Temperatures

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - ~~27°F~~ All temperatures CONDITIONS

(From Table A-~~1~~ 11A On ~~Distillate Oil~~ Natural Gas; 70% LOAD

All Other Calculations on Spreadsheet are Identical.)

Table A-~~1~~ 11A: (Note: all other data not calculated but supplied by Manufacturer)

Heat Input (10^6 Btu/hr): 100.0 MMBtu/hr (given)

~~Power (kW) x Heat Rate (10^6 Btu/kWh)~~

~~183,700 x 10,070/10^6 = 1,849.9 x 10^6 Btu/hr~~

~~Fuel Oil~~ Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

~~1,849.9~~ 100.0 x 10^6 ÷ ~~18,550~~ 23,839 = ~~99,723~~ 4,194.8 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

~~3,743,000~~ 5,244 lb/hr x 1,545 x (~~1,060~~ 200°F + 460°F) ÷ (~~28.25~~ 28.00 x 2,116.8 lb/ft²)

÷ 60(min/hr)

= ~~2,450,287~~ 1,504 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

~~3,743,000~~ 5,244 lb/hr x 1,545 x (68°F + 460°F) ÷ (~~28.25~~ 28.00 x 2,116.8) ÷ 60

= ~~851,152~~ 1,203 scfm

Duct Burner - Supplemental Filing
Natural Gas
70% LOAD
All Temperatures

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,504 ~~2,450,287~~ acfm x (200 ~~205~~°F + 460°F) ÷ (200 ~~1,060~~°F + 460°F)

= 1,504 ~~1,072,001~~ acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

1,504 ~~1,072,001~~ ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 0.1 ~~70.2~~ ft/sec

Table A-12A ~~A-2~~:

PM emissions in tons per year

0.01 lb/mmBtu x 100.0 mmBtu/hr x 8760 hr/yr ÷ 2000 lb/ton

~~17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton~~

= 4.38 ~~2.6~~ ton/yr

SO_2 Emissions--Oil (lb/hr)

105,263 cf/hr ~~99,722.9 lb/hr~~ x 1.0 gr/100 cf ~~0.0005 lb S/lb~~ x 2 lb SO_2/lb S x 1.0 lb/7000 gr

= 0.30 ~~99.72~~ lb/hr

NO_x Emissions (lb/hr) ~~See Note B~~:

~~42 ppm x [20.9 x (1 - 11.59/100) - 10.96] x 2,116.8 lb/ft²~~
~~x 2,450,287 ft³/min~~

~~x 46 (molecular wgt NO₂) x 60 min/hr ÷ [1,545 x (1,060°F + 460°F)~~
~~x 5.9 x 10⁶ (adjust for ppm)]~~

~~= 326.2 lb/hr~~

0.1 lb/mmBtu x 100.0 mmBtu/hr = 10.0 lb/hr

Duct Burner - Supplemental Firing
Natural Gas
70% LOAD
All Temperatures

CO Emissions (lb/hr) ~~- See Note C~~:

~~30 ppm x (1 - 11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft² x 28 (molecular wgt. of carbon)~~

~~x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10⁶)~~

~~= 98.4 lb/hr~~

0.10 lb/MMBtu x 100.0 MMBtu/hr = 10.0 lb/hr

VOC Emissions (lb/hr) ~~- See Note C:~~

~~3.5 ppm x (1-11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft² x 16 (molecular wgt. of methane)~~

~~x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10⁶)~~

~~= 6.56 lb/hr~~

0.029 lb/MMBtu x 100.0 MMBtu/hr = 2.90 lb/hr

Lead Emissions (lb/hr): Not Applicable

~~8.9 lb/10¹² Btu x 1,849.9 x 10⁶ Btu/hr = 1.65 x 10⁻² lb/hr~~

Table A-~~3~~13A:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

105,263 cf/hr x 1.0 gr/100 cf x 2 lb SO_2 / lb S x 1.0 lb/7000 gr

~~99,722.9 lb/hr x 0.0005 lb S/lb~~ x ~~3.06~~ 1.53 lb H_2SO_4/lb SO_2 x ~~0.05~~ 0.08 (converted)

= ~~12.2~~ 3.68×10^{-2} lb/hr

Tables ~~A-4 and A-5~~ A-13A, A-14A:

EPA emission factor as noted in printout; example for manganese:

~~1,849.9 (MMBtu) x 14 lb/10¹² Btu~~ Not Applicable

~~= 2.59 x 10⁻² lb/hr~~

7/31/92

Emission Calculations, Tables A-13A, A-14A

Manufacturer/Model: Duct Burner
Fuel Type: Natural Gas
Load: 70%
Ambient Temperature: All temperatures

Arsenic: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Beryllium: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Mercury: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Fluoride: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Nickel: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Cadmium: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Chromium: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Copper: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Vanadium: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Selenium: ____ lb/10^{12} Btu x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu = NA lb/hr

Polycyclic Organic Matter: 1.113 lb/10^{12} Btu x 100.0 MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= 1.11×10^{-4} lb/hr

Formaldehyde: 88.12 lb/10^{12} Btu x 100.0 MMBtu/hr + 10^6 MMBtu/10^{12} Btu = 8.81×10^{-3} lb/hr

Antimony: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Barium: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Cobalt: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Zinc: ____ pg/J x 2.324 lb/10^{12} Btu/pg/J x ____ MMBtu/hr + 10^6 MMBtu/10^{12} Btu
= NA lb/hr

Chlorine: ____ ppm x ______ lb/hr fuel oil + 10^6 = NA lb/hr

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT/M$$

where: P = pressure = 2116.8 lb/ft^2
m = mass flow of gas (lb/hr)
R = universal gas constant = 1545
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)

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

(From Method 20; Equation 20-1)

$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$; (From Method 20; Equation 20-1)

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$\begin{aligned} m_{CO} &= PV_{CO\ Act}M_{CO}\ /\ RT \\ &= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT \end{aligned}$$

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

JUL 15 1992

RECEIVED

JUL 20 1992

Bureau of Air Regulation

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

RE: Central Florida Power Limited Partnership, Central Florida Cogeneration Plant (PSD-FL-190)

Dear Mr. Fancy:

This is to acknowledge receipt of the Prevention of Significant Deterioration (PSD) permit application package for the above referenced facility. The proposed facility will be a combined cycle cogeneration power plant, nominally rated at 206 megawatts for the facility. The proposed project consists of one advanced technology heavy-duty industrial gas turbine electric generating unit, with a duct burner-fired heat recovery steam generator, and a steam turbine generator.

The applicant proposes to limit NO_x emissions from the combustion turbine through advanced dry low-NO_x combustors and water injection, to limit NO_x emissions from the duct burner through combustion design, to limit CO emissions from the combustion turbine and duct burner through combustion design, and to limit VOC, PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuels.

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on the package. If you have any questions or comments, please contact Mr. Scott Davis 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: M. Baig
C. Holladay
B. Thomas, SW Dist.
C. Shaver, NPS
K. Kosky, KBN
CHF/PL

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APPENDIX A

EMISSION CALCULATIONS

Table A-1. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	183,700.0		159,200.0		142,500.0
Heat Rate (Btu/kwh)	10,070.0		10,320.0		10,650.0
Heat Input (mmBtu/hr)	1,849.9		1,642.9		1,517.6
Fuel Oil (lb/hr)	99,722.9		88,568.4		81,812.7
Fuel:					
Heat Content,LHV (Btu/lb)	18,550		18,550		18,550
CT Exhaust:					
Volume Flow (acfm)	2,450,287		2,288,314		2,190,589
Volume Flow (scfm)	851,152		773,514		728,816
Mass Flow (lb/hr)	3,743,000		3,390,000		3,189,000
Temperature (oF)	1,060		1,102		1,127
Moisture (% Vol.)	11.59		12.40		12.71
Oxygen (% Vol.)	10.96		10.95		11.03
Molecular Weight	28.25		28.15		28.10
Water Injected (lb/hr)	135,390		107,070		92,890
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,072,001		974,218		917,922
Temperature (oF)	205		205		205
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	70.2		63.8		60.1
Stack Height (ft)	180		180		180

Source: General Electric, 1992.

Table A-3. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	7.77E-03		6.90E-03		6.37E-03
	TPY	1.17E-03		1.04E-03		9.56E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	4.62E-03		4.11E-03		3.79E-03
	TPY	6.94E-04		6.16E-04		5.69E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	5.55E-03		4.93E-03		4.55E-03
	TPY	8.32E-04		7.39E-04		6.83E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	6.02E-02		5.35E-02		4.94E-02
	TPY	9.03E-03		8.02E-03		7.41E-03
Sulfuric Acid	% of SO2	8		8		8
Mist	lb/hr	1.22E+01		1.08E+01		1.00E+01
	TPY	1.83E+00		1.63E+00		1.50E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-2. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	17.0		17.0		17.0
lb/hr	17.0		17.0		17.0
TPY	2.6		2.6		2.6
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	99.72		88.57		81.81
TPY	15.0		13.3		12.3
Nitrogen Oxides					
Basis, ppm* (1)	42.0		42.0		42.0
lb/hr	326.2		290.2		268.0
TPY	48.9		43.5		40.2
Carbon Monoxide					
Basis, ppm+ (1)	30.0		30.0		30.0
lb/hr	98.4		88.6		83.2
TPY	14.8		13.3		12.5
VOCs (as methane)					
Basis, ppm+ (1)	4.0		3.9		4.1
lb/hr	7.50		6.58		6.50
TPY	1.1		1.0		1.0
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.65E-02		1.46E-02		1.35E-02
TPY	2.47E-03		2.19E-03		2.03E-03

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: (1) General Electric, 1992; (2) EPA, 1990

Table A-4. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	2.59E-02		2.30E-02		2.12E-02
	TPY	3.88E-03		3.45E-03		3.19E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	3.14E-01		2.79E-01		2.58E-01
	TPY	4.72E-02		4.19E-02		3.87E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.94E-02		1.73E-02		1.59E-02
	TPY	2.91E-03		2.59E-03		2.39E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	8.79E-02		7.80E-02		7.21E-02
	TPY	1.32E-02		1.17E-02		1.08E-02
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	5.18E-01		4.60E-01		4.25E-01
	TPY	7.77E-02		6.90E-02		6.37E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	1.29E-01		1.14E-01		1.05E-01
	TPY	1.93E-02		1.71E-02		1.58E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	4.33E-02		3.85E-02		3.55E-02
	TPY	6.50E-03		5.77E-03		5.33E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	5.14E-04		4.57E-04		4.22E-04
Matter	TPY	7.71E-05		6.85E-05		6.33E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	7.49E-01		6.65E-01		6.15E-01
	TPY	1.12E-01		9.98E-02		9.22E-02
Carbon	% Exhaust Gas	5.32		5.21		5.11
Dioxide	lb/hr	3.10E+05		2.76E+05		2.55E+05
	TPY	4.65E+04		4.14E+04		3.83E+04

Source: (1) EPA, 1990

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	4.04E-02		3.59E-02		3.32E-02
	TPY	6.06E-03		5.38E-03		4.97E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	3.61E-02		3.21E-02		2.96E-02
	TPY	5.42E-03		4.81E-03		4.44E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.68E-02		1.49E-02		1.38E-02
	TPY	2.51E-03		2.23E-03		2.06E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	1.26E+00		1.12E+00		1.04E+00
	TPY	1.90E-01		1.68E-01		1.56E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	4.99E-02		4.43E-02		4.09E-02
	TPY	7.48E-03		6.64E-03		6.14E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	170,700.0	151,900.0	147,100.0	142,700.0	131,800.0
Heat Rate (Btu/kwh)	9,460.0	9,750.0	9,860.0	9,970.0	10,230.0
Heat Input (mmBtu/hr)	1,614.8	1,481.0	1,450.4	1,422.7	1,348.3
Natural Gas (lb/hr)	75,055.6	68,836.9	67,413.7	66,126.8	62,668.6
(cf/hr)	1,699,813	1,558,974	1,526,743	1,497,599	1,419,278
Fuel:					
Heat Content, LHV (Btu/lb)	21,515	21,515	21,515	21,515	21,515
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
Volume Flow (scfm)	808,255	753,259	740,784	729,581	700,802
Mass Flow (lb/hr)	3,582,000	3,322,000	3,262,000	3,202,000	3,077,000
Temperature (oF)	1,078	1,110	1,117	1,124	1,140
Moisture (% Vol.)	7.61	8.83	9.21	10.05	9.91
Oxygen (% Vol.)	12.71	12.56	12.51	12.36	12.48
Molecular Weight	28.46	28.33	28.28	28.19	28.20
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,017,973	948,707	932,995	918,885	882,639
Temperature (oF)	205	205	205	205	205
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	66.7	62.1	61.1	60.2	57.8
Stack Height (ft)	180	180	180	180	180

Source: General Electric, 1992.

Table A-7. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	9.00	9.00	9.00	9.00	9.00
lb/hr	9.00	9.00	9.00	9.00	9.00
TPY	38.07	38.07	38.07	38.07	38.07
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	4.86	4.45	4.36	4.28	4.06
TPY	20.54	18.84	18.45	18.10	17.15
Nitrogen Oxides					
Basis, ppm* (1)	25.0	25.0	25.0	25.0	25.0
lb/hr	161.9	148.5	145.3	142.6	135.0
TPY	684.72	627.98	614.78	603.09	571.14
Carbon Monoxide					
Basis, ppm+ (1)	15.0	15.0	15.0	15.0	15.0
lb/hr	48.8	44.9	44.0	42.9	41.3
TPY	206.55	189.96	186.03	181.52	174.63
VOCs (as methane)					
Basis, ppm+ (1)	1.5	1.5	1.5	1.6	1.5
lb/hr	2.79	2.57	2.55	2.62	2.36
TPY	11.80	10.85	10.77	11.06	9.98
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: General Electric, 1992.

Table A-8. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	6.26E-01	5.74E-01	5.62E-01	5.52E-01	5.23E-01
	TPY	2.65E+00	2.43E+00	2.38E+00	2.33E+00	2.21E+00

Source: EPA, 1990

Table A-9. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.80E-03	1.65E-03	1.61E-03	1.58E-03	1.50E-03
Matter	TPY	7.60E-03	6.97E-03	6.83E-03	6.70E-03	6.35E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.42E-01	1.31E-01	1.28E-01	1.25E-01	1.19E-01
	TPY	6.02E-01	5.52E-01	5.41E-01	5.30E-01	5.03E-01
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	2.07E+05	1.90E+05	1.86E+05	1.82E+05	1.73E+05
	TPY	8.76E+05	8.03E+05	7.86E+05	7.72E+05	7.31E+05

Source: (1) EPA, 1990

GE7FATOT
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Table A-10. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-11. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,515	1,515	1,515	1,515	1,515
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	205	205	205	205	205
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-12. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-13. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-14. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-15. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	17.00	17.00	17.00	9.00	9.00	9.00	1.00	1.00	1.00	18.00	18.00	18.00
TPY	2.55	2.55	2.55	38.07	38.07	38.07	4.38	4.38	4.38	45.00	45.00	45.00
Sulfur Dioxide:												
lb/hr	99.72	88.57	81.81	4.86	4.36	4.06	0.30	0.30	0.30	100.02	88.87	82.11
TPY	14.96	13.29	12.27	20.54	18.45	17.15	1.32	1.32	1.32	36.82	33.05	30.74
Nitrogen Oxides:												
lb/hr	326.22	290.19	268.04	161.87	145.34	135.02	10.00	10.00	10.00	336.22	300.19	278.04
TPY	48.93	43.53	40.21	684.72	614.78	571.14	43.80	43.80	43.80	777.46	702.11	655.15
Carbon Monoxide:												
lb/hr	98.41	88.62	83.20	48.83	43.98	41.28	10.00	10.00	10.00	108.41	98.62	93.20
TPY	14.76	13.29	12.48	206.55	186.03	174.63	43.80	43.80	43.80	265.12	243.12	230.91
VOCs (as methane):												
lb/hr	7.50	6.58	6.50	2.79	2.55	2.36	2.90	2.90	2.90	10.40	9.48	9.40
TPY	1.12	0.99	0.97	11.80	10.77	9.98	12.70	12.70	12.70	25.63	24.46	23.66
Lead:												
lb/hr	1.65E-02	1.46E-02	1.35E-02	NA	NA	NA	NA	NA	NA	1.65E-02	1.46E-02	1.35E-02
TPY	2.47E-03	2.19E-03	2.03E-03	NA	NA	NA	NA	NA	NA	2.47E-03	2.19E-03	2.03E-03

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Table A-16. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	7.77E-03	6.90E-03	6.37E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.77E-03	6.90E-03	6.37E-03
	TPY	1.17E-03	1.04E-03	9.56E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.17E-03	1.04E-03	9.56E-04
Beryllium													
	lb/hr	4.62E-03	4.11E-03	3.79E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.62E-03	4.11E-03	3.79E-03
	TPY	6.94E-04	6.16E-04	5.69E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.94E-04	6.16E-04	5.69E-04
Mercury													
	lb/hr	5.55E-03	4.93E-03	4.55E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.55E-03	4.93E-03	4.55E-03
	TPY	8.32E-04	7.39E-04	6.83E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	8.32E-04	7.39E-04	6.83E-04
Fluoride													
	lb/hr	6.02E-02	5.35E-02	4.94E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.02E-02	5.35E-02	4.94E-02
	TPY	9.03E-03	8.02E-03	7.41E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.03E-03	8.02E-03	7.41E-03
Sulfuric Acid													
Mist	lb/hr	1.22E+01	1.08E+01	1.00E+01	6.26E-01	5.62E-01	5.23E-01	3.88E-02	3.88E-02	3.88E-02	1.23E+01	1.09E+01	1.01E+01
	TPY	1.83E+00	1.63E+00	1.50E+00	2.65E+00	2.38E+00	2.21E+00	1.70E-01	1.70E-01	1.70E-01	4.65E+00	4.18E+00	3.89E+00

Table A-17. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	2.59E-02	2.30E-02	2.12E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.59E-02	2.30E-02	2.12E-02
	TPY	3.88E-03	3.45E-03	3.19E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.88E-03	3.45E-03	3.19E-03
Nickel	lb/hr	3.14E-01	2.79E-01	2.58E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.14E-01	2.79E-01	2.58E-01
	TPY	4.72E-02	4.19E-02	3.87E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.72E-02	4.19E-02	3.87E-02
Cadmium	lb/hr	1.94E-02	1.73E-02	1.59E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.94E-02	1.73E-02	1.59E-02
	TPY	2.91E-03	2.59E-03	2.39E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.91E-03	2.59E-03	2.39E-03
Chromium	lb/hr	8.79E-02	7.80E-02	7.21E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	8.79E-02	7.80E-02	7.21E-02
	TPY	1.32E-02	1.17E-02	1.08E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.32E-02	1.17E-02	1.08E-02
Copper	lb/hr	5.18E-01	4.60E-01	4.25E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.18E-01	4.60E-01	4.25E-01
	TPY	7.77E-02	6.90E-02	6.37E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.77E-02	6.90E-02	6.37E-02
Vanadium	lb/hr	1.29E-01	1.14E-01	1.05E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.29E-01	1.14E-01	1.05E-01
	TPY	1.93E-02	1.71E-02	1.58E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.93E-02	1.71E-02	1.58E-02
Selenium	lb/hr	4.33E-02	3.85E-02	3.55E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.33E-02	3.85E-02	3.55E-02
	TPY	6.50E-03	5.77E-03	5.33E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.50E-03	5.77E-03	5.33E-03
Polycyclic Organic Matter	lb/hr	5.14E-04	4.57E-04	4.22E-04	1.80E-03	1.61E-03	1.50E-03	1.11E-04	1.11E-04	1.11E-04	1.91E-03	1.73E-03	1.61E-03
	TPY	7.71E-05	6.85E-05	6.33E-05	7.60E-03	6.83E-03	6.35E-03	4.87E-04	4.87E-04	4.87E-04	8.17E-03	7.38E-03	6.90E-03
Formaldehyde	lb/hr	7.49E-01	6.65E-01	6.15E-01	1.42E-01	1.28E-01	1.19E-01	8.81E-03	8.81E-03	8.81E-03	7.58E-01	6.74E-01	6.23E-01
	TPY	1.12E-01	9.98E-02	9.22E-02	6.02E-01	5.41E-01	5.03E-01	3.86E-02	3.86E-02	3.86E-02	7.53E-01	6.79E-01	6.33E-01
Carbon Dioxide	lb/hr	3.10E+05	2.76E+05	2.55E+05	2.07E+05	1.86E+05	1.73E+05	3.08E+02	3.02E+02	2.97E+02	3.11E+05	2.76E+05	2.55E+05
	TPY	4.65E+04	4.14E+04	3.83E+04	8.76E+05	7.86E+05	7.31E+05	1.35E+03	1.32E+03	1.30E+03	9.24E+05	8.29E+05	7.71E+05

Table A-18. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	4.04E-02	3.59E-02	3.32E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.04E-02	3.59E-02	3.32E-02
	TPY	6.06E-03	5.38E-03	4.97E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	6.06E-03	5.38E-03	4.97E-03
Barium													
	lb/hr	3.61E-02	3.21E-02	2.96E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.61E-02	3.21E-02	2.96E-02
	TPY	5.42E-03	4.81E-03	4.44E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	5.42E-03	4.81E-03	4.44E-03
Cobalt													
	lb/hr	1.68E-02	1.49E-02	1.38E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.68E-02	1.49E-02	1.38E-02
	TPY	2.51E-03	2.23E-03	2.06E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.51E-03	2.23E-03	2.06E-03
Zinc													
	lb/hr	1.26E+00	1.12E+00	1.04E+00	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.26E+00	1.12E+00	1.04E+00
	TPY	1.90E-01	1.68E-01	1.56E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.90E-01	1.68E-01	1.56E-01
Chlorine													
	lb/hr	4.99E-02	4.43E-02	4.09E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.99E-02	4.43E-02	4.09E-02
	TPY	7.48E-03	6.64E-03	6.14E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	7.48E-03	6.64E-03	6.14E-03

Table A-1A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	129,200.0		111,000.0		98,500.0
Heat Rate (Btu/kwh)	11,430.0		11,800.0		12,280.0
Heat Input (mmBtu/hr)	1,476.8		1,309.8		1,209.6
Fuel Oil (lb/hr)	79,609.5		70,609.2		65,206.5
Fuel:					
Heat Content,LHV (Btu/lb)	18,550		18,550		18,550
CT Exhaust:					
Volume Flow (acfm)	1,988,010		1,869,045		1,802,083
Volume Flow (scfm)	645,553		597,370		573,193
Mass Flow (lb/hr)	2,837,000		2,619,000		2,510,000
Temperature (oF)	1,166		1,192		1,200
Moisture (% Vol.)	11.96		12.40		12.48
Oxygen (% Vol.)	10.57		10.81		11.07
Molecular Weight	28.23		28.16		28.13
Water Injected (lb/hr)	105,120		80,490		68,760
HRSG Stack (without duct burner):					
Volume Flow (acfm)	806,941		746,713		716,491
Temperature (oF)	200		200		200
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	52.9		48.9		46.9
Stack Height (ft)	180		180		180

Source: General Electric, 1992.

Table A-2A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	17.0		17.0		17.0
lb/hr	17.0		17.0		17.0
TPY	2.6		2.6		2.6
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	79.61		70.61		65.21
TPY	11.9		10.6		9.8
Nitrogen Oxides					
Basis, ppm* (1)	42.0		42.0		42.0
lb/hr	257.7		228.4		211.0
TPY	38.7		34.3		31.7
Carbon Monoxide					
Basis, ppm+ (1)	30.0		30.0		30.0
lb/hr	74.3		68.4		65.6
TPY	11.1		10.3		9.8
VOCs (as methane)					
Basis, ppm+ (1)	4.0		4.0		4.1
lb/hr	5.66		5.21		5.12
TPY	0.8		0.8		0.8
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.31E-02		1.17E-02		1.08E-02
TPY	1.97E-03		1.75E-03		1.61E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) General Electric, 1992; (2) EPA, 1990

Table A-3A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	6.20E-03		5.50E-03		5.08E-03
	TPY	9.30E-04		8.25E-04		7.62E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	3.69E-03		3.27E-03		3.02E-03
	TPY	5.54E-04		4.91E-04		4.54E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	4.43E-03		3.93E-03		3.63E-03
	TPY	6.65E-04		5.89E-04		5.44E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	4.80E-02		4.26E-02		3.94E-02
	TPY	7.21E-03		6.39E-03		5.90E-03
Sulfuric Acid	% of SO2	8		8		8
Mist	lb/hr	9.75E+00		8.65E+00		7.99E+00
	TPY	1.46E+00		1.30E+00		1.20E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-4A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	2.07E-02		1.83E-02		1.69E-02
	TPY	3.10E-03		2.75E-03		2.54E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	2.51E-01		2.23E-01		2.06E-01
	TPY	3.77E-02		3.34E-02		3.08E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.55E-02		1.38E-02		1.27E-02
	TPY	2.33E-03		2.06E-03		1.91E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	7.01E-02		6.22E-02		5.75E-02
	TPY	1.05E-02		9.33E-03		8.62E-03
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	4.13E-01		3.67E-01		3.39E-01
	TPY	6.20E-02		5.50E-02		5.08E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	1.03E-01		9.10E-02		8.41E-02
	TPY	1.54E-02		1.37E-02		1.26E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	3.46E-02		3.07E-02		2.83E-02
	TPY	5.19E-03		4.60E-03		4.25E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	4.11E-04		3.64E-04		3.36E-04
Matter	TPY	6.16E-05		5.46E-05		5.04E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	5.98E-01		5.30E-01		4.90E-01
	TPY	8.97E-02		7.96E-02		7.35E-02
Carbon	% Exhaust Gas	5.54		5.31		5.11
Dioxide	lb/hr	2.45E+05		2.17E+05		2.01E+05
	TPY	3.68E+04		3.26E+04		3.01E+04

Source: (1) EPA, 1990

Table A-5A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	3.23E-02		2.86E-02		2.64E-02
	TPY	4.84E-03		4.29E-03		3.96E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	2.88E-02		2.56E-02		2.36E-02
	TPY	4.32E-03		3.84E-03		3.54E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.34E-02		1.19E-02		1.10E-02
	TPY	2.01E-03		1.78E-03		1.64E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	1.01E+00		8.95E-01		8.26E-01
	TPY	1.51E-01		1.34E-01		1.24E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	3.98E-02		3.53E-02		3.26E-02
	TPY	5.97E-03		5.30E-03		4.89E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	119,900.0	106,500.0	103,100.0	99,500.0	90,900.0
Heat Rate (Btu/kwh)	10,770.0	11,070.0	11,340.0	11,510.0	11,890.0
Heat Input (mmBtu/hr)	1,291.3	1,179.0	1,169.2	1,145.2	1,080.8
Natural Gas (lb/hr)	60,019.7	54,796.9	54,341.3	53,230.1	50,234.8
(cf/hr)	1,359,287	1,241,005	1,230,688	1,205,521	1,137,685
Fuel:					
Heat Content, LHV (Btu/lb)	21,515	21,515	21,515	21,515	21,515
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
Volume Flow (scfm)	619,500	588,641	581,580	575,224	558,903
Mass Flow (lb/hr)	2,744,000	2,595,000	2,560,000	2,524,000	2,454,000
Temperature (oF)	1,177	1,195	1,199	1,200	1,200
Moisture (% Vol.)	7.84	8.98	9.34	10.14	9.89
Oxygen (% Vol.)	12.46	12.41	12.39	12.28	12.52
Molecular Weight	28.45	28.32	28.27	28.18	28.20
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack (without duct burner):					
Volume Flow (acfm)	774,375	735,801	726,975	719,030	698,629
Temperature (oF)	200	200	200	200	200
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	50.7	48.2	47.6	47.1	45.8
Stack Height (ft)	180	180	180	180	180

Source: General Electric, 1992.

Table A-7A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	9.00	9.00	9.00	9.00	9.00
lb/hr	9.00	9.00	9.00	9.00	9.00
TPY	38.07	38.07	38.07	38.07	38.07
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	3.88	3.55	3.52	3.44	3.25
TPY	16.43	15.00	14.87	14.57	13.75
Nitrogen Oxides					
Basis, ppm* (1)	25.0	25.0	25.0	25.0	25.0
lb/hr	127.9	118.1	115.7	113.5	107.1
TPY	540.88	499.71	489.59	480.01	452.93
Carbon Monoxide					
Basis, ppm+ (1)	15.0	15.0	15.0	15.0	15.0
lb/hr	37.3	35.0	34.5	33.8	32.9
TPY	157.92	148.20	145.84	142.98	139.31
VOCs (as methane)					
Basis, ppm+ (1)	1.5	1.5	1.5	1.6	1.5
lb/hr	2.13	2.00	2.00	2.06	1.88
TPY	9.02	8.47	8.44	8.71	7.96
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: General Electric, 1992.

Table A-8A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	5.01E-01	4.57E-01	4.53E-01	4.44E-01	4.19E-01
	TPY	2.12E+00	1.93E+00	1.92E+00	1.88E+00	1.77E+00

Source: EPA, 1990

Table A-9A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.44E-03	1.31E-03	1.30E-03	1.27E-03	1.20E-03
Matter	TPY	6.08E-03	5.55E-03	5.50E-03	5.39E-03	5.09E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.14E-01	1.04E-01	1.03E-01	1.01E-01	9.52E-02
	TPY	4.81E-01	4.39E-01	4.36E-01	4.27E-01	4.03E-01
Carbon	% Exhaust Gas	3.85	3.75	3.72	3.68	3.58
Dioxide	lb/hr	1.63E+05	1.51E+05	1.48E+05	1.45E+05	1.37E+05
	TPY	6.91E+05	6.40E+05	6.27E+05	6.14E+05	5.80E+05

Source: (1) EPA, 1990

Table A-10A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-11A. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,504	1,504	1,504	1,504	1,504
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	200	200	200	200	200
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-12A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-13A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-14A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-15A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	17.00	17.00	17.00	9.00	9.00	9.00	1.00	1.00	1.00	18.00	18.00	18.00
TPY	2.55	2.55	2.55	38.07	38.07	38.07	4.38	4.38	4.38	45.00	45.00	45.00
Sulfur Dioxide:												
lb/hr	79.61	70.61	65.21	3.88	3.52	3.25	0.30	0.30	0.30	79.91	70.91	65.51
TPY	11.94	10.59	9.78	16.43	14.87	13.75	1.32	1.32	1.32	29.69	26.78	24.85
Nitrogen Oxides:												
lb/hr	257.71	228.37	211.04	127.87	115.74	107.07	10.00	10.00	10.00	267.71	238.37	221.04
TPY	38.66	34.26	31.66	540.88	489.59	452.93	43.80	43.80	43.80	623.33	567.64	528.38
Carbon Monoxide:												
lb/hr	74.33	68.44	65.61	37.33	34.48	32.93	10.00	10.00	10.00	84.33	78.44	75.61
TPY	11.15	10.27	9.84	157.92	145.84	139.31	43.80	43.80	43.80	212.87	199.91	192.95
VOCs (as methane):												
lb/hr	5.66	5.21	5.12	2.13	2.00	1.88	2.90	2.90	2.90	8.56	8.11	8.02
TPY	0.85	0.78	0.77	9.02	8.44	7.96	12.70	12.70	12.70	22.58	21.93	21.43
Lead:												
lb/hr	1.31E-02	1.17E-02	1.08E-02	NA	NA	NA	NA	NA	NA	1.31E-02	1.17E-02	1.08E-02
TPY	1.97E-03	1.75E-03	1.61E-03	NA	NA	NA	NA	NA	NA	1.97E-03	1.75E-03	1.61E-03

Table A-16A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	6.20E-03	5.50E-03	5.08E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.20E-03	5.50E-03	5.08E-03
	TPY	9.30E-04	8.25E-04	7.62E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.30E-04	8.25E-04	7.62E-04
Beryllium													
	lb/hr	3.69E-03	3.27E-03	3.02E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.69E-03	3.27E-03	3.02E-03
	TPY	5.54E-04	4.91E-04	4.54E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.54E-04	4.91E-04	4.54E-04
Mercury													
	lb/hr	4.43E-03	3.93E-03	3.63E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.43E-03	3.93E-03	3.63E-03
	TPY	6.65E-04	5.89E-04	5.44E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.65E-04	5.89E-04	5.44E-04
Fluoride													
	lb/hr	4.80E-02	4.26E-02	3.94E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.80E-02	4.26E-02	3.94E-02
	TPY	7.21E-03	6.39E-03	5.90E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.21E-03	6.39E-03	5.90E-03
Sulfuric Acid Mist	lb/hr	9.75E+00	8.65E+00	7.99E+00	5.01E-01	4.53E-01	4.19E-01	3.88E-02	3.88E-02	3.88E-02	9.79E+00	8.69E+00	8.03E+00
	TPY	1.46E+00	1.30E+00	1.20E+00	2.12E+00	1.92E+00	1.77E+00	1.70E-01	1.70E-01	1.70E-01	3.75E+00	3.39E+00	3.14E+00

Table A-17A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	2.07E-02	1.83E-02	1.69E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.07E-02	1.83E-02	1.69E-02
	TPY	3.10E-03	2.75E-03	2.54E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.10E-03	2.75E-03	2.54E-03
Nickel	lb/hr	2.51E-01	2.23E-01	2.06E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.51E-01	2.23E-01	2.06E-01
	TPY	3.77E-02	3.34E-02	3.08E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.77E-02	3.34E-02	3.08E-02
Cadmium	lb/hr	1.55E-02	1.38E-02	1.27E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.55E-02	1.38E-02	1.27E-02
	TPY	2.33E-03	2.06E-03	1.91E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.33E-03	2.06E-03	1.91E-03
Chromium	lb/hr	7.01E-02	6.22E-02	5.75E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.01E-02	6.22E-02	5.75E-02
	TPY	1.05E-02	9.33E-03	8.62E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.05E-02	9.33E-03	8.62E-03
Copper	lb/hr	4.13E-01	3.67E-01	3.39E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.13E-01	3.67E-01	3.39E-01
	TPY	6.20E-02	5.50E-02	5.08E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.20E-02	5.50E-02	5.08E-02
Vanadium	lb/hr	1.03E-01	9.10E-02	8.41E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.03E-01	9.10E-02	8.41E-02
	TPY	1.54E-02	1.37E-02	1.26E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.54E-02	1.37E-02	1.26E-02
Selenium	lb/hr	3.46E-02	3.07E-02	2.83E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.46E-02	3.07E-02	2.83E-02
	TPY	5.19E-03	4.60E-03	4.25E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.19E-03	4.60E-03	4.25E-03
Polycyclic Organic Matter	lb/hr	4.11E-04	3.64E-04	3.36E-04	1.44E-03	1.30E-03	1.20E-03	1.11E-04	1.11E-04	1.11E-04	1.55E-03	1.41E-03	1.31E-03
	TPY	6.16E-05	5.46E-05	5.04E-05	6.08E-03	5.50E-03	5.09E-03	4.87E-04	4.87E-04	4.87E-04	6.63E-03	6.05E-03	5.63E-03
Formaldehyde	lb/hr	5.98E-01	5.30E-01	4.90E-01	1.14E-01	1.03E-01	9.52E-02	8.81E-03	8.81E-03	8.81E-03	6.07E-01	5.39E-01	4.99E-01
	TPY	8.97E-02	7.96E-02	7.35E-02	4.81E-01	4.36E-01	4.03E-01	3.86E-02	3.86E-02	3.86E-02	6.10E-01	5.54E-01	5.15E-01
Carbon Dioxide	lb/hr	2.45E+05	2.17E+05	2.01E+05	1.63E+05	1.48E+05	1.37E+05	3.08E+02	3.02E+02	2.97E+02	2.45E+05	2.18E+05	2.01E+05
	TPY	3.68E+04	3.26E+04	3.01E+04	6.91E+05	6.27E+05	5.80E+05	1.35E+03	1.32E+03	1.30E+03	7.29E+05	6.61E+05	6.11E+05

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Table A-18A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	3.23E-02	2.86E-02	2.64E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.23E-02	2.86E-02	2.64E-02
	TPY	4.84E-03	4.29E-03	3.96E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.84E-03	4.29E-03	3.96E-03
Barium													
	lb/hr	2.88E-02	2.56E-02	2.36E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.88E-02	2.56E-02	2.36E-02
	TPY	4.32E-03	3.84E-03	3.54E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.32E-03	3.84E-03	3.54E-03
Cobalt													
	lb/hr	1.34E-02	1.19E-02	1.10E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.34E-02	1.19E-02	1.10E-02
	TPY	2.01E-03	1.78E-03	1.64E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.01E-03	1.78E-03	1.64E-03
Zinc													
	lb/hr	1.01E+00	8.95E-01	8.26E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.01E+00	8.95E-01	8.26E-01
	TPY	1.51E-01	1.34E-01	1.24E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.51E-01	1.34E-01	1.24E-01
Chlorine													
	lb/hr	3.98E-02	3.53E-02	3.26E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.98E-02	3.53E-02	3.26E-02
	TPY	5.97E-03	5.30E-03	4.89E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	5.97E-03	5.30E-03	4.89E-03

Table A-19. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	171,730.0		160,550.0		145,180.0
Heat Rate (Btu/kwh)	9,290.0		9,570.0		9,880.0
Heat Input (mmBtu/hr)	1,595.4		1,536.5		1,434.4
Fuel Oil (lb/hr)	88,142.1		84,887.5		79,247.4
Fuel:					
Heat Content,LHV (Btu/lb)	18,100		18,100		18,100
CT Exhaust:					
Volume Flow (acfm)	2,378,254		2,347,829		2,246,134
Volume Flow (scfm)	817,525		792,111		749,184
Mass Flow (lb/hr)	3,590,650		3,479,030		3,281,070
Temperature (oF)	1,076		1,105		1,123
Moisture (% Vol.)	11.78		11.78		12.44
Oxygen (% Vol.)	11.85		11.85		11.79
Molecular Weight	28.21		28.21		28.13
Water Injected (lb/hr)	132,210		127,340		118,880
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,029,648		997,640		943,575
Temperature (oF)	205		205		205
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	67.4		65.3		61.8
Stack Height (ft)	180		180		180

Source: Westinghouse, 1992.

Table A-20. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	40.4		39.1		36.7
lb/hr	40.4		39.1		36.7
TPY	6.1		5.9		5.5
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	91.05		87.01		82.02
TPY	13.7		13.1		12.3
Nitrogen Oxides					
Basis, ppm* (1)	44.5		42.0		42.0
lb/hr	290.9		266.0		248.7
TPY	43.6		39.9		37.3
Carbon Monoxide					
Basis, ppm+ (1)	52.0		51.6		51.4
lb/hr	163.5		157.0		147.0
TPY	24.5		23.6		22.0
VOCs (as methane)					
Basis, ppm+ (1)	10.5		10.5		10.5
lb/hr	18.86		18.28		17.16
TPY	2.8		2.7		2.6
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.42E-02		1.37E-02		1.28E-02
TPY	2.13E-03		2.05E-03		1.91E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) Westinghouse, 1992; (2) EPA, 1990

Table A-21. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	6.70E-03		6.45E-03		6.02E-03
	TPY	1.01E-03		9.68E-04		9.04E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	3.99E-03		3.84E-03		3.59E-03
	TPY	5.98E-04		5.76E-04		5.38E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	4.79E-03		4.61E-03		4.30E-03
	TPY	7.18E-04		6.91E-04		6.45E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	5.19E-02		5.00E-02		4.67E-02
	TPY	7.79E-03		7.50E-03		7.00E-03
Sulfuric Acid Mist	% of SO2	8		8		8
	lb/hr	1.12E+01		1.07E+01		1.00E+01
	TPY	1.67E+00		1.60E+00		1.51E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-22. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	2.23E-02		2.15E-02		2.01E-02
	TPY	3.35E-03		3.23E-03		3.01E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	2.71E-01		2.61E-01		2.44E-01
	TPY	4.07E-02		3.92E-02		3.66E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.68E-02		1.61E-02		1.51E-02
	TPY	2.51E-03		2.42E-03		2.26E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	7.58E-02		7.30E-02		6.81E-02
	TPY	1.14E-02		1.09E-02		1.02E-02
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	4.47E-01		4.30E-01		4.02E-01
	TPY	6.70E-02		6.45E-02		6.02E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	1.11E-01		1.07E-01		9.97E-02
	TPY	1.66E-02		1.60E-02		1.50E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	3.74E-02		3.60E-02		3.36E-02
	TPY	5.60E-03		5.40E-03		5.04E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	4.44E-04		4.27E-04		3.99E-04
Matter	TPY	6.65E-05		6.41E-05		5.98E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	6.46E-01		6.22E-01		5.81E-01
	TPY	9.69E-02		9.33E-02		8.71E-02
Carbon	% Exhaust Gas	5.00		5.00		4.94
Dioxide	lb/hr	2.80E+05		2.71E+05		2.54E+05
	TPY	4.20E+04		4.07E+04		3.80E+04

Source: (1) EPA, 1990

Table A-23. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	3.49E-02		3.36E-02		3.13E-02
	TPY	5.23E-03		5.03E-03		4.70E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	3.11E-02		3.00E-02		2.80E-02
	TPY	4.67E-03		4.50E-03		4.20E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.45E-02		1.39E-02		1.30E-02
	TPY	2.17E-03		2.09E-03		1.95E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	1.09E+00		1.05E+00		9.80E-01
	TPY	1.64E-01		1.57E-01		1.47E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	4.41E-02		4.24E-02		3.96E-02
	TPY	6.61E-03		6.37E-03		5.94E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-24. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	168,010.0	146,540.0	141,910.0	138,110.0	127,710.0
Heat Rate (Btu/kwh)	9,480.0	9,910.0	10,020.0	10,120.0	10,400.0
Heat Input (mmBtu/hr)	1,592.7	1,452.2	1,421.9	1,397.7	1,328.2
Natural Gas (lb/hr)	80,849.5	73,716.3	72,179.6	70,947.9	67,420.5
(cf/hr)	1,676,563	1,528,644	1,496,777	1,471,235	1,398,088
Fuel:					
Heat Content, LHV (Btu/lb)	19,700	19,700	19,700	19,700	19,700
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	2,386,805	2,256,129	2,226,061	2,203,500	2,134,002
Volume Flow (scfm)	828,011	770,528	757,320	745,800	716,764
Mass Flow (lb/hr)	3,673,720	3,402,010	3,339,570	3,276,980	3,150,780
Temperature (oF)	1,062	1,086	1,092	1,100	1,112
Moisture (% Vol.)	7.23	8.42	8.79	9.65	9.53
Oxygen (% Vol.)	13.04	12.92	12.87	12.69	12.79
Molecular Weight	28.50	28.36	28.32	28.22	28.23
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,042,855	970,456	953,821	939,313	902,743
Temperature (oF)	205	205	205	205	205
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	68.3	63.6	62.5	61.5	59.1
Stack Height (ft)	180	180	180	180	180

Source: Westinghouse, 1992.

Table A-25. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	6.40	6.00	5.90	5.80	5.60
lb/hr	6.40	6.00	5.90	5.80	5.60
TPY	27.07	25.38	24.96	24.53	23.69
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	4.79	4.37	4.28	4.20	3.99
TPY	20.26	18.47	18.09	17.78	16.90
Nitrogen Oxides					
Basis, ppm* (1)	26.5	25.0	25.0	25.0	25.0
lb/hr	169.0	145.4	142.3	140.2	133.1
TPY	715.05	615.25	602.04	592.91	562.93
Carbon Monoxide					
Basis, ppm+ (1)	10.0	10.4	10.3	10.2	10.2
lb/hr	33.5	32.0	31.0	30.0	28.8
TPY	141.65	135.33	131.20	126.74	121.97
VOCs (as methane)					
Basis, ppm+ (1)	4.2	4.1	4.1	4.2	4.3
lb/hr	8.04	7.21	7.05	7.05	6.95
TPY	34.00	30.49	29.84	29.82	29.38
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: Westinghouse, 1992.

Table A-26. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	6.18E-01	5.63E-01	5.51E-01	5.42E-01	5.15E-01
	TPY	2.61E+00	2.38E+00	2.33E+00	2.29E+00	2.18E+00

Source: EPA, 1990

Table A-27. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.77E-03	1.62E-03	1.58E-03	1.56E-03	1.48E-03
Matter	TPY	7.50E-03	6.84E-03	6.69E-03	6.58E-03	6.25E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.40E-01	1.28E-01	1.25E-01	1.23E-01	1.17E-01
	TPY	5.94E-01	5.41E-01	5.30E-01	5.21E-01	4.95E-01
Carbon	% Exhaust Gas	3.61	3.54	3.53	3.52	3.48
Dioxide	lb/hr	2.05E+05	1.87E+05	1.83E+05	1.80E+05	1.71E+05
	TPY	8.66E+05	7.91E+05	7.75E+05	7.61E+05	7.23E+05

Source: (1) EPA, 1990

Table A-28. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-29. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,515	1,515	1,515	1,515	1,515
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	205	205	205	205	205
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-30. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-31. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-32. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-33. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, Base Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	40.40	39.10	36.70	6.40	5.90	5.60	1.00	1.00	1.00	41.40	40.10	37.70
TPY	6.06	5.87	5.51	27.07	24.96	23.69	4.38	4.38	4.38	37.51	35.20	33.57
Sulfur Dioxide:												
lb/hr	91.05	87.01	82.02	4.79	4.28	3.99	0.30	0.30	0.30	91.35	87.31	82.32
TPY	13.66	13.05	12.30	20.26	18.09	16.90	1.32	1.32	1.32	35.24	32.46	30.52
Nitrogen Oxides:												
lb/hr	290.93	266.05	248.65	169.04	142.33	133.08	10.00	10.00	10.00	300.93	276.05	258.65
TPY	43.64	39.91	37.30	715.05	602.04	562.93	43.80	43.80	43.80	802.48	685.75	644.03
Carbon Monoxide:												
lb/hr	163.49	157.04	146.99	33.49	31.02	28.83	10.00	10.00	10.00	173.49	167.04	156.99
TPY	24.52	23.56	22.05	141.65	131.20	121.97	43.80	43.80	43.80	209.97	198.55	187.82
VOCs (as methane):												
lb/hr	18.86	18.28	17.16	8.04	7.05	6.95	2.90	2.90	2.90	21.76	21.18	20.06
TPY	2.83	2.74	2.57	34.00	29.84	29.38	12.70	12.70	12.70	49.53	45.29	44.66
Lead:												
lb/hr	1.42E-02	1.37E-02	1.28E-02	NA	NA	NA	NA	NA	NA	1.42E-02	1.37E-02	1.28E-02
TPY	2.13E-03	2.05E-03	1.91E-03	NA	NA	NA	NA	NA	NA	2.13E-03	2.05E-03	1.91E-03

Table A-34. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	6.70E-03	6.45E-03	6.02E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.70E-03	6.45E-03	6.02E-03
	TPY	1.01E-03	9.68E-04	9.04E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.01E-03	9.68E-04	9.04E-04
Beryllium													
	lb/hr	3.99E-03	3.84E-03	3.59E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.99E-03	3.84E-03	3.59E-03
	TPY	5.98E-04	5.76E-04	5.38E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.98E-04	5.76E-04	5.38E-04
Mercury													
	lb/hr	4.79E-03	4.61E-03	4.30E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.79E-03	4.61E-03	4.30E-03
	TPY	7.18E-04	6.91E-04	6.45E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.18E-04	6.91E-04	6.45E-04
Fluoride													
	lb/hr	5.19E-02	5.00E-02	4.67E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.19E-02	5.00E-02	4.67E-02
	TPY	7.79E-03	7.50E-03	7.00E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.79E-03	7.50E-03	7.00E-03
Sulfuric Acid Mist	lb/hr	1.12E+01	1.07E+01	1.00E+01	6.18E-01	5.51E-01	5.15E-01	3.88E-02	3.88E-02	3.88E-02	1.12E+01	1.07E+01	1.01E+01
	TPY	1.67E+00	1.60E+00	1.51E+00	2.61E+00	2.33E+00	2.18E+00	1.70E-01	1.70E-01	1.70E-01	4.46E+00	4.10E+00	3.86E+00

Table A-35. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	2.23E-02	2.15E-02	2.01E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.23E-02	2.15E-02	2.01E-02
	TPY	3.35E-03	3.23E-03	3.01E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.35E-03	3.23E-03	3.01E-03
Nickel	lb/hr	2.71E-01	2.61E-01	2.44E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.71E-01	2.61E-01	2.44E-01
	TPY	4.07E-02	3.92E-02	3.66E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.07E-02	3.92E-02	3.66E-02
Cadmium	lb/hr	1.68E-02	1.61E-02	1.51E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.68E-02	1.61E-02	1.51E-02
	TPY	2.51E-03	2.42E-03	2.26E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.51E-03	2.42E-03	2.26E-03
Chromium	lb/hr	7.58E-02	7.30E-02	6.81E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.58E-02	7.30E-02	6.81E-02
	TPY	1.14E-02	1.09E-02	1.02E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.14E-02	1.09E-02	1.02E-02
Copper	lb/hr	4.47E-01	4.30E-01	4.02E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.47E-01	4.30E-01	4.02E-01
	TPY	6.70E-02	6.45E-02	6.02E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.70E-02	6.45E-02	6.02E-02
Vanadium	lb/hr	1.11E-01	1.07E-01	9.97E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.11E-01	1.07E-01	9.97E-02
	TPY	1.66E-02	1.60E-02	1.50E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.66E-02	1.60E-02	1.50E-02
Selenium	lb/hr	3.74E-02	3.60E-02	3.36E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.74E-02	3.60E-02	3.36E-02
	TPY	5.60E-03	5.40E-03	5.04E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.60E-03	5.40E-03	5.04E-03
Polycyclic Organic Matter	lb/hr	4.44E-04	4.27E-04	3.99E-04	1.77E-03	1.58E-03	1.48E-03	1.11E-04	1.11E-04	1.11E-04	1.88E-03	1.69E-03	1.59E-03
	TPY	6.65E-05	6.41E-05	5.98E-05	7.50E-03	6.69E-03	6.25E-03	4.87E-04	4.87E-04	4.87E-04	8.05E-03	7.25E-03	6.80E-03
Formaldehyde	lb/hr	6.46E-01	6.22E-01	5.81E-01	1.40E-01	1.25E-01	1.17E-01	8.81E-03	8.81E-03	8.81E-03	6.55E-01	6.31E-01	5.90E-01
	TPY	9.69E-02	9.33E-02	8.71E-02	5.94E-01	5.30E-01	4.95E-01	3.86E-02	3.86E-02	3.86E-02	7.29E-01	6.62E-01	6.21E-01
Carbon Dioxide	lb/hr	2.80E+05	2.71E+05	2.54E+05	2.05E+05	1.83E+05	1.71E+05	3.08E+02	3.02E+02	2.97E+02	2.80E+05	2.72E+05	2.54E+05
	TPY	4.20E+04	4.07E+04	3.80E+04	8.66E+05	7.75E+05	7.23E+05	1.35E+03	1.32E+03	1.30E+03	9.10E+05	8.17E+05	7.62E+05

Table A-19A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	134,010.0		112,180.0		101,370.0
Heat Rate (Btu/kwh)	9,940.0		10,590.0		11,010.0
Heat Input (mmBtu/hr)	1,332.1		1,188.0		1,116.1
Fuel Oil (lb/hr)	73,594.4		65,634.6		61,662.1
Fuel:					
Heat Content,LHV (Btu/lb)	18,100		18,100		18,100
CT Exhaust:					
Volume Flow (acfm)	2,038,400		1,904,295		1,835,565
Volume Flow (scfm)	700,700		642,471		612,241
Mass Flow (lb/hr)	3,099,150		2,824,930		2,684,120
Temperature (oF)	1,076		1,105		1,123
Moisture (% Vol.)	9.79		11.19		11.87
Oxygen (% Vol.)	12.48		12.36		12.30
Molecular Weight	28.41		28.24		28.16
Water Injected (lb/hr)	110,400		98,460		92,490
HRSG Stack (without duct burner):					
Volume Flow (acfm)	875,875		803,089		765,302
Temperature (oF)	200		200		200
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	57.4		52.6		50.1
Stack Height (ft)	180		180		180

Source: Westinghouse, 1992.

Table A-20A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	34.2		30.8		29.2
lb/hr	34.2		30.8		29.2
TPY	5.1		4.6		4.4
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	75.95		68.00		64.01
TPY	11.4		10.2		9.6
Nitrogen Oxides					
Basis, ppm* (1)	44.3		42.0		42.0
lb/hr	240.0		203.1		191.0
TPY	36.0		30.5		28.7
Carbon Monoxide					
Basis, ppm+ (1)	51.5		51.5		51.5
lb/hr	142.0		128.0		121.0
TPY	21.3		19.2		18.2
VOCs (as methane)					
Basis, ppm+ (1)	10.2		10.6		10.5
lb/hr	16.06		15.07		14.11
TPY	2.4		2.3		2.1
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.19E-02		1.06E-02		9.93E-03
TPY	1.78E-03		1.59E-03		1.49E-03

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: (1) Westinghouse, 1992; (2) EPA, 1990

Table A-21A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	5.59E-03		4.99E-03		4.69E-03
	TPY	8.39E-04		7.48E-04		7.03E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	3.33E-03		2.97E-03		2.79E-03
	TPY	5.00E-04		4.45E-04		4.19E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	4.00E-03		3.56E-03		3.35E-03
	TPY	5.99E-04		5.35E-04		5.02E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	4.33E-02		3.87E-02		3.63E-02
	TPY	6.50E-03		5.80E-03		5.45E-03
Sulfuric Acid Mist	% of SO2	8		8		8
	lb/hr	9.30E+00		8.33E+00		7.84E+00
	TPY	1.40E+00		1.25E+00		1.18E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-22A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	1.86E-02		1.66E-02		1.56E-02
	TPY	2.80E-03		2.49E-03		2.34E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	2.26E-01		2.02E-01		1.90E-01
	TPY	3.40E-02		3.03E-02		2.85E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.40E-02		1.25E-02		1.17E-02
	TPY	2.10E-03		1.87E-03		1.76E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	6.33E-02		5.64E-02		5.30E-02
	TPY	9.49E-03		8.46E-03		7.95E-03
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	3.73E-01		3.33E-01		3.13E-01
	TPY	5.59E-02		4.99E-02		4.69E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	9.26E-02		8.26E-02		7.76E-02
	TPY	1.39E-02		1.24E-02		1.16E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	3.12E-02		2.78E-02		2.61E-02
	TPY	4.68E-03		4.17E-03		3.92E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	3.70E-04		3.30E-04		3.10E-04
Matter	TPY	5.55E-05		4.95E-05		4.65E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	5.39E-01		4.81E-01		4.52E-01
	TPY	8.09E-02		7.22E-02		6.78E-02
Carbon	% Exhaust Gas	4.84		4.71		4.64
Dioxide	lb/hr	2.32E+05		2.07E+05		1.95E+05
	TPY	3.49E+04		3.11E+04		2.92E+04

Source: (1) EPA, 1990

Table A-23A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	2.91E-02		2.60E-02		2.44E-02
	TPY	4.36E-03		3.89E-03		3.66E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	2.60E-02		2.32E-02		2.18E-02
	TPY	3.90E-03		3.48E-03		3.27E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.21E-02		1.08E-02		1.01E-02
	TPY	1.81E-03		1.62E-03		1.52E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	9.10E-01		8.12E-01		7.63E-01
	TPY	1.37E-01		1.22E-01		1.14E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	3.68E-02		3.28E-02		3.08E-02
	TPY	5.52E-03		4.92E-03		4.62E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-24A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	117,480.0	102,390.0	99,140.0	96,460.0	89,150.0
Heat Rate (Btu/kwh)	10,540.0	11,100.0	11,240.0	11,370.0	11,720.0
Heat Input (mmBtu/hr)	1,238.2	1,136.5	1,114.3	1,096.8	1,044.8
Natural Gas (lb/hr)	62,854.8	57,691.8	56,565.2	55,672.6	53,037.5
(cf/hr)	1,303,410	1,196,346	1,172,983	1,154,474	1,099,829
Fuel:					
Heat Content, LHV (Btu/lb)	19,700	19,700	19,700	19,700	19,700
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,913,170	1,830,092	1,811,447	1,796,734	1,752,347
Volume Flow (scfm)	635,317	607,729	601,537	596,651	581,911
Mass Flow (lb/hr)	2,818,340	2,684,320	2,652,890	2,623,320	2,559,380
Temperature (oF)	1,130	1,130	1,130	1,130	1,130
Moisture (% Vol.)	7.25	8.28	8.62	9.42	9.24
Oxygen (% Vol.)	13.01	13.07	13.06	12.94	13.12
Molecular Weight	28.49	28.37	28.33	28.24	28.25
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack (without duct burner):					
Volume Flow (acfm)	794,146	759,661	751,922	745,814	727,389
Temperature (oF)	200	200	200	200	200
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	52.0	49.8	49.2	48.8	47.6
Stack Height (ft)	180	180	180	180	180

Source: Westinghouse, 1992.

Table A-25A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	4.90	4.70	4.70	4.60	4.50
lb/hr	4.90	4.70	4.70	4.60	4.50
TPY	20.73	19.88	19.88	19.46	19.04
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	3.72	3.42	3.35	3.30	3.14
TPY	15.75	14.46	14.18	13.95	13.29
Nitrogen Oxides					
Basis, ppm* (1)	26.5	25.0	25.0	25.0	25.0
lb/hr	130.0	112.5	110.2	108.5	103.3
TPY	550.04	475.84	466.27	458.87	436.90
Carbon Monoxide					
Basis, ppm+ (1)	10.0	10.3	10.4	10.2	10.2
lb/hr	25.7	25.0	25.0	24.0	23.5
TPY	108.66	105.87	105.72	101.65	99.34
VOCs (as methane)					
Basis, ppm+ (1)	4.1	4.3	4.4	4.5	4.0
lb/hr	6.02	5.97	6.02	6.06	5.26
TPY	25.46	25.26	25.49	25.63	22.26
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: Westinghouse, 1992.

Table A-26A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	4.80E-01	4.41E-01	4.32E-01	4.25E-01	4.05E-01
	TPY	2.03E+00	1.86E+00	1.83E+00	1.80E+00	1.71E+00

Source: EPA, 1990

Table A-27A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.38E-03	1.26E-03	1.24E-03	1.22E-03	1.16E-03
Matter	TPY	5.83E-03	5.35E-03	5.25E-03	5.16E-03	4.92E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.09E-01	1.00E-01	9.82E-02	9.66E-02	9.21E-02
	TPY	4.62E-01	4.24E-01	4.15E-01	4.09E-01	3.89E-01
Carbon	% Exhaust Gas	3.62	3.47	3.43	3.41	3.33
Dioxide	lb/hr	1.58E+05	1.44E+05	1.41E+05	1.39E+05	1.33E+05
	TPY	6.67E+05	6.11E+05	5.98E+05	5.90E+05	5.62E+05

Source: (1) EPA, 1990

Table A-28A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-29A. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,504	1,504	1,504	1,504	1,504
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	200	200	200	200	200
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-30A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-31A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-32A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-33A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	34.20	30.80	29.20	4.90	4.70	4.50	1.00	1.00	1.00	35.20	31.80	30.20
TPY	5.13	4.62	4.38	20.73	19.88	19.04	4.38	4.38	4.38	30.24	28.88	27.80
Sulfur Dioxide:												
lb/hr	75.95	68.00	64.01	3.72	3.35	3.14	0.30	0.30	0.30	76.25	68.30	64.31
TPY	11.39	10.20	9.60	15.75	14.18	13.29	1.32	1.32	1.32	28.46	25.69	24.21
Nitrogen Oxides:												
lb/hr	240.01	203.12	191.00	130.03	110.23	103.29	10.00	10.00	10.00	250.01	213.12	201.00
TPY	36.00	30.47	28.65	550.04	466.27	436.90	43.80	43.80	43.80	629.84	540.54	509.35
Carbon Monoxide:												
lb/hr	141.97	127.98	121.02	25.69	24.99	23.48	10.00	10.00	10.00	151.97	137.98	131.02
TPY	21.30	19.20	18.15	108.66	105.72	99.34	43.80	43.80	43.80	173.76	168.72	161.29
VOCs (as methane):												
lb/hr	16.06	15.07	14.11	6.02	6.02	5.26	2.90	2.90	2.90	18.96	17.97	17.01
TPY	2.41	2.26	2.12	25.46	25.49	22.26	12.70	12.70	12.70	40.57	40.45	37.08
Lead:												
lb/hr	1.19E-02	1.06E-02	9.93E-03	NA	NA	NA	NA	NA	NA	1.19E-02	1.06E-02	9.93E-03
TPY	1.78E-03	1.59E-03	1.49E-03	NA	NA	NA	NA	NA	NA	1.78E-03	1.59E-03	1.49E-03

Table A-34A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	5.59E-03	4.99E-03	4.69E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.59E-03	4.99E-03	4.69E-03
	TPY	8.39E-04	7.48E-04	7.03E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	8.39E-04	7.48E-04	7.03E-04
Beryllium													
	lb/hr	3.33E-03	2.97E-03	2.79E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.33E-03	2.97E-03	2.79E-03
	TPY	5.00E-04	4.45E-04	4.19E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.00E-04	4.45E-04	4.19E-04
Mercury													
	lb/hr	4.00E-03	3.56E-03	3.35E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.00E-03	3.56E-03	3.35E-03
	TPY	5.99E-04	5.35E-04	5.02E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.99E-04	5.35E-04	5.02E-04
Fluoride													
	lb/hr	4.33E-02	3.87E-02	3.63E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.33E-02	3.87E-02	3.63E-02
	TPY	6.50E-03	5.80E-03	5.45E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.50E-03	5.80E-03	5.45E-03
Sulfuric Acid Mist	lb/hr	9.30E+00	8.33E+00	7.84E+00	4.80E-01	4.32E-01	4.05E-01	3.88E-02	3.88E-02	3.88E-02	9.34E+00	8.37E+00	7.88E+00
	TPY	1.40E+00	1.25E+00	1.18E+00	2.03E+00	1.83E+00	1.71E+00	1.70E-01	1.70E-01	1.70E-01	3.60E+00	3.25E+00	3.06E+00

Table A-35A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	1.86E-02	1.66E-02	1.56E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.86E-02	1.66E-02	1.56E-02
	TPY	2.80E-03	2.49E-03	2.34E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.80E-03	2.49E-03	2.34E-03
Nickel	lb/hr	2.26E-01	2.02E-01	1.90E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.26E-01	2.02E-01	1.90E-01
	TPY	3.40E-02	3.03E-02	2.85E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.40E-02	3.03E-02	2.85E-02
Cadmium	lb/hr	1.40E-02	1.25E-02	1.17E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.40E-02	1.25E-02	1.17E-02
	TPY	2.10E-03	1.87E-03	1.76E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.10E-03	1.87E-03	1.76E-03
Chromium	lb/hr	6.33E-02	5.64E-02	5.30E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.33E-02	5.64E-02	5.30E-02
	TPY	9.49E-03	8.46E-03	7.95E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.49E-03	8.46E-03	7.95E-03
Copper	lb/hr	3.73E-01	3.33E-01	3.13E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.73E-01	3.33E-01	3.13E-01
	TPY	5.59E-02	4.99E-02	4.69E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.59E-02	4.99E-02	4.69E-02
Vanadium	lb/hr	9.26E-02	8.26E-02	7.76E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.26E-02	8.26E-02	7.76E-02
	TPY	1.39E-02	1.24E-02	1.16E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.39E-02	1.24E-02	1.16E-02
Selenium	lb/hr	3.12E-02	2.78E-02	2.61E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.12E-02	2.78E-02	2.61E-02
	TPY	4.68E-03	4.17E-03	3.92E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.68E-03	4.17E-03	3.92E-03
Polycyclic Organic Matter	lb/hr	3.70E-04	3.30E-04	3.10E-04	1.38E-03	1.24E-03	1.16E-03	1.11E-04	1.11E-04	1.11E-04	1.49E-03	1.35E-03	1.27E-03
	TPY	5.55E-05	4.95E-05	4.65E-05	5.83E-03	5.25E-03	4.92E-03	4.87E-04	4.87E-04	4.87E-04	6.37E-03	5.78E-03	5.45E-03
Formaldehyde	lb/hr	5.39E-01	4.81E-01	4.52E-01	1.09E-01	9.82E-02	9.21E-02	8.81E-03	8.81E-03	8.81E-03	5.48E-01	4.90E-01	4.61E-01
	TPY	8.09E-02	7.22E-02	6.78E-02	4.62E-01	4.15E-01	3.89E-01	3.86E-02	3.86E-02	3.86E-02	5.81E-01	5.26E-01	4.96E-01
Carbon Dioxide	lb/hr	2.32E+05	2.07E+05	1.95E+05	1.58E+05	1.41E+05	1.33E+05	3.08E+02	3.02E+02	2.97E+02	2.33E+05	2.08E+05	1.95E+05
	TPY	3.49E+04	3.11E+04	2.92E+04	6.67E+05	5.98E+05	5.62E+05	1.35E+03	1.32E+03	1.30E+03	7.03E+05	6.30E+05	5.92E+05

Table A-36A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility- Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	2.91E-02	2.60E-02	2.44E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.91E-02	2.60E-02	2.44E-02
	TPY	4.36E-03	3.89E-03	3.66E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.36E-03	3.89E-03	3.66E-03
Barium													
	lb/hr	2.60E-02	2.32E-02	2.18E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.60E-02	2.32E-02	2.18E-02
	TPY	3.90E-03	3.48E-03	3.27E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.90E-03	3.48E-03	3.27E-03
Cobalt													
	lb/hr	1.21E-02	1.08E-02	1.01E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.21E-02	1.08E-02	1.01E-02
	TPY	1.81E-03	1.62E-03	1.52E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.81E-03	1.62E-03	1.52E-03
Zinc													
	lb/hr	9.10E-01	8.12E-01	7.63E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	9.10E-01	8.12E-01	7.63E-01
	TPY	1.37E-01	1.22E-01	1.14E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.37E-01	1.22E-01	1.14E-01
Chlorine													
	lb/hr	3.68E-02	3.28E-02	3.08E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.68E-02	3.28E-02	3.08E-02
	TPY	5.52E-03	4.92E-03	4.62E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	5.52E-03	4.92E-03	4.62E-03

EXAMPLE CALCULATIONS

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS

(From Table A-1 On Distillate Oil;

All Other Calculations on Spreadsheet are Identical.)

Table A-1: (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)

183,700 x 10,070/10^6 = 1,849.9 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

1,849.9 x 10^6 ÷ 18,550 = 99,723 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

3,743,000 lb/hr x 1,545 x (1,060°F + 460°F) ÷ (28.25 x 2,116.8 lb/ft^2)

÷ 60(min/hr)

= 2,450,287 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

3,743,000 lb/hr x 1,545 x (68°F + 460°F) ÷ (28.25 x 2,116.8) ÷ 60

= 851,152 scfm

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,450,287 acfm x (205°F + 460°F) ÷ (1,060°F + 460°F)

= 1,072,001 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

1,072,001 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 70.2 ft/sec

Table A-2:

PM emissions in tons per year

17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

99,722.9 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 99.72 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - 11.59/100) - 10.96] x 2,116.8 lb/ft^2
x 2,450,287 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,060°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= 326.2 lb/hr

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - 11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10^6)

= 98.4 lb/hr

VOC Emissions (lb/hr) - See Note C:

3.5 ppm x (1-11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10^6)

= 6.56 lb/hr

Lead Emissions (lb/hr):

8.9 $lb/10^{12}$ Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr

<u>Table A-3</u>:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

99,722.9 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.05 (converted)

= 12.2 lb/hr

<u>Tables A-4 and A-5</u>:

EPA emission factor as noted in printout; example for manganese:

1,849.9 (MMBtu) x 14 $lb/10^{12}$ Btu

= 2.59 x 10^{-2} lb/hr

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT/M$$

where: P = pressure = 2116.8 lb/ft^2
m = mass flow of gas (lb/hr)
R = universal gas constant = 1545
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)

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

(From Method 20; Equation 20-1)

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O);\ \text{(From Method 20; Equation 20-1)}$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$\begin{aligned} m_{CO} &= PV_{CO\ Act}M_{CO} \ / \ RT \\ &= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO} \ / \ RT \end{aligned}$$

EMISSION FACTORS

PB91-126003

United States Environmental Protection Agency

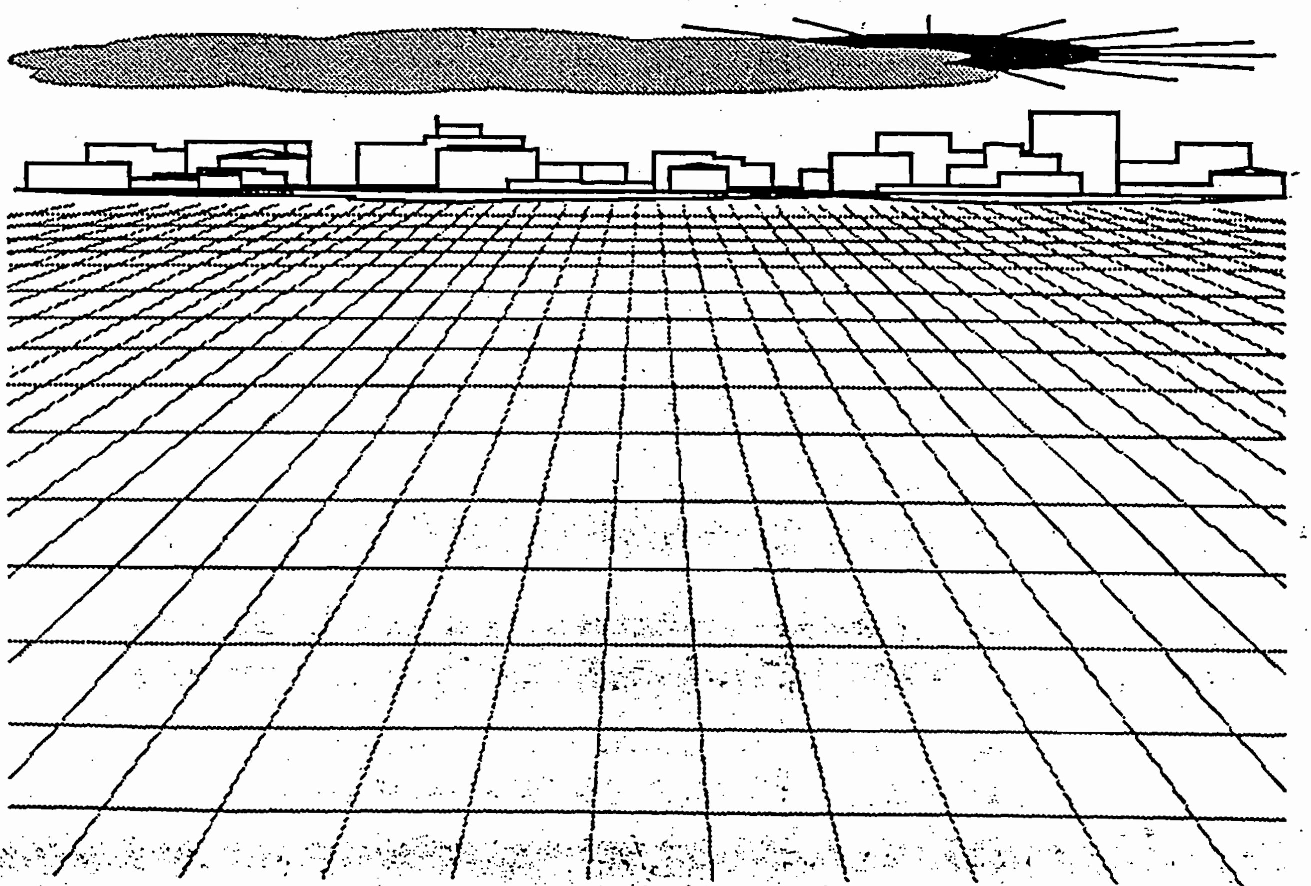
Office of Air Quality Planning And Standards Research Triangle Park, NC 27711

EPA-450/2-90-011
October 1990

AIR

EPA

TOXIC AIR POLLUTANT EMISSION FACTORS - A COMPILATION FOR SELECTED AIR TOXIC COMPOUNDS AND SOURCES, SECOND EDITION



[redacted] production [redacted] nonferrous alloy facility [redacted] charged [redacted] Judgement [redacted]

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Nonferrous metals production	3341	Melt furnace at permanent magnet alloy facility	304	Nickel	7440020	2 lb/ton of nickel charged	Controlled by fabric filter, based on engineering judgement	110
Nonferrous metals production	3341	Melt furnace at superalloy facility	304	Nickel	7440020	2 lb/ton of nickel charged	Controlled by fabric filter, based on engineering judgement	110
Nonylphenol production	2869	Fugitive emissions	301	Phenol	108952	0.38 lb/ton used	From engineering estimates	13
Nonylphenol production	2869	General emissions	301	Phenol	108952	1.6 lb/ton used	From engineering estimates	13
Nonylphenol production	2869	Storage	407084	Phenol	108952	0.02 lb/ton used	From engineering estimates	13
Oil and coal combustion	49	Stack - particulate	102	Polychlorinated dibenzo-p-dioxins, total		1.34 x 10E-4 lb/ton	No penta homologue included, one location, TCDD detection = 4 x 10E-5 lb/ton	119
Oil and coal combustion	49	Stack - particulate	102	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1746016	Not detectable	One location, detection limit = 2 x 10E-5 lb/ton	119
Oil combustion		Fuel oil		Ammonia	7664417	0.8 lb/1000 gallons fuel oil burned	Sources emitting > 100 tons NH3/year	179
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	2.06 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	0.50 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	0.42 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	19 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	9.31 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36

P 265 659 313

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PS Form **3800**, April 1995

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Florida Power Corp.
3201 34th St. South
St. Petersburg, Fl
33733

4a. Article Number
P 265 659 313

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	2.28 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	1.90 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	2.8 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	1.58 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.35 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.15 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	2.65 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.59 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.25 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	10.5 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	7.45 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	1.58 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	0.43 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	15.7 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	46.84 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	9.90 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	3.96 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	47.8 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	27.8 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	13.92 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	3.84 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	21 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	12.18 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	6.09 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	1.68 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	280 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	165.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	42 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	278 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	165.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired	1	Copper	7440508	42.0 lb/10E12 Btu	Controlled with ESP, calculated based [illegible]	[illegible]

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Oil-fired boiler or furnace, util/commerc/industr/residential	1	Formaldehyde	50000	405 lb/10E12 Btu	Uncontrolled, based on emissions testing	34
Oil combustion		Industrial, commercial, and residential boilers	1	Lead	7439921	8.9 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use distillate oil	34
Oil combustion		Utility boiler	101004	Lead	7439921	28 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use residual oil	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	14 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	6.44 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	3.08 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	1.54 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	26 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	11.96 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	5.72 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	2.84 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.0 lb/10E12 Btu	Uncontrolled, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.0 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	2.25 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	0.78 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.2 lb/10E12 Btu	Uncontrolled, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.2 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	2.4 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	0.83 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	170 lb/10E12 Btu	Uncontrolled, based on engineering judgement	34
Oil combustion		Distillate oil-fired	1	Nickel	7440020	86.7 lb/10E12 Btu	Controlled by multiclone, based on engineering	[illegible]

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	47.6 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	6.8 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	1260 lb/10E12 Btu	Uncontrolled, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	642.6 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	352.8 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	50.4 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	34
Oil combustion		Cast iron sectional boilers, distillate oil	10300501	Polycyclic organic matter		34.5 lb/10E12 Btu	Uncontrolled, home heating application	114
Oil combustion		Distillate watertube boilers	10300501	Polycyclic organic matter		0.278 lb/10E12 Btu heat input	Uncontrolled	114
Oil combustion		Hot air furnace, distillate oil	10300501	Polycyclic organic matter		0.324 lb/10E12 Btu	Uncontrolled, same reference also lists <15.4 for same boiler/fuel type	114
Oil combustion		Scotch marine boilers, distillate oil	10300501	Polycyclic organic matter		41.04 lb/10E12 Btu	Uncontrolled	114
Oil combustion	49	Flue gas	1	2,3,7,8-Tetrachlorodibenzofuran		Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<0.67-<1.3ng/m3	119
Oil combustion	49	Boiler flue gas	1	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1746016	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<4.2-<7.9 ng/m3	119
Oil combustion, commercial		Scotch marine boilers, residual oil	10300401	Polycyclic organic matter		2.203 lb/10E12 Btu heat input	Uncontrolled, represents benzo(a)pyrene only	114

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion, commercial		Tangential furnace, distillate oil	103005	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Tangential furnace, residual oil	103004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, distillate oil	103005	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, residual oil	103004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired tangential furnaces	103005	Vanadium	7440622	69.5 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired wall furnaces	103005	Vanadium	7440622	69.5 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Residual oil-fired tangential furnaces	103004	Vanadium	7440622	8487 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Residual oil-fired wall furnaces	103004	Vanadium	7440622	8487 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Oil-fired boiler	102005	Lead	7439921	0.00015 lbs/10E6 BTU heat input	Uncontrolled emissions, based on 1 test	189
Oil combustion, industrial		Steam atomized watertube, residual oil	10200401	Polycyclic organic matter		8.33 lb/10E12 Btu heat input	Uncontrolled, represents mostly particulate POM	114
Oil combustion, industrial		Watertube, residual oil	10200401	Polycyclic organic matter		1.46 lb/10E12 Btu heat input	Uncontrolled, represents both gaseous and particulate POM	114
Oil combustion, industrial		Tangential furnace	102	Selenium	7782492	4.63 lb/10E12 Btu	Controlled by scrubber, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Tangential furnace	102	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Selenium	7782492	4.63 lb/10E12 Btu	Controlled by scrubber, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Tangential furnace	102	Vanadium	7440622	602.9 lb/10E12 Btu	Controlled by scrubber, based on reported emissions and engineering judgement	54

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion, industrial		Wall furnace	102	Vanadium	7440622	602.9 lb/10E12 Btu	Controlled by scrubber, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Vanadium	7440622	3014 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, residential		Distillate oil-fired furnaces		Selenium	7782492	6.72 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, residential		Distillate oil-fired boiler, util/commerc/industr/residential		Vanadium	7440622	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility		Face-fired, residual oil	10100401	Polycyclic organic matter		0.858 lb/10E12 Btu heat input	Uncontrolled, represents both gaseous and particulate POM	114
Oil combustion, utility		Tangential-fired, residual oil	10100404	Polycyclic organic matter		5.79 lb/10E12 Btu heat input	Cyclone controls, represents both gaseous and particulate POM	114
Oil combustion, utility		Wall-fired, residual oil	10100401	Polycyclic organic matter		9.04 lb/10E12 Btu heat input	Uncontrolled, ave. of 4 values ranging from 0.45-12.3 pg/J, represents gaseous & particulate POM	114
Oil combustion, utility	491	Oil-fired utility boiler	101004	Sulfuric acid	7664939	8.5 x % sulfur in fuel ng/J	Controlled emissions, FGD system with 50% efficiency for sulfuric acid mist	213
Oil combustion, utility	491	Oil-fired utility boiler	101004	Sulfuric acid	7664939	16.9 x % sulfur in fuel ng/J	Uncontrolled emissions	213
Oil combustion, utility	4911	Tangential-fired, residual oil	101004	Selenium	7782492	4.638 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Tangential-fired, residual oil	101004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Wall furnace, residual oil	101004	Selenium	7782492	4.638 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Wall furnace, residual oil	101004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired tangential furnaces	101004	Vanadium	7440622	702.6 lb/10E12 Btu	Controlled by ESP, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired tangential furnaces	101004	Vanadium	7440622	3515 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired wall furnaces	101004	Vanadium	7440622	702.6 lb/10E12 Btu	Controlled by ESP, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired wall furnaces	101004	Vanadium	7440622	3515 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil shale retorting	1311	Entire process		Mercury	7439976	2.2 x 10E-4 lbs/barrel oil produced	Includes Hg compound form, assumes fac. using 13,000 tons/day raw shale to prod. 12,000 bbl/day oil	40
Oil shale retorting	1311	Modified in situ retort		Polycyclic organic matter		0.0073 lb/hr	Based on offgas concentration and flow rate	114
Open burning		Area source	50300201	Acetaldehyde	75070	0.72 - 1.46 lb/ton wood burned	Estimated from a total aldehyde value of 10.4 lb/ton	130
Open burning		Automobile body burning	50300203	Polycyclic organic matter		0.22 lb/ton waste	Based on concentration measured in smoke plume	114
Open burning		Automobile tire burning	50300203	Polycyclic organic matter		0.48 lb/ton waste	Based on concentration measured in smoke plume	114
Open burning		Grass, leaves, branches	50300201	Polycyclic organic matter		0.005 - 0.0184 lb/ton waste	Based on concentration measured in smoke plume	114
Open burning		Leaf burning	50300201	Polycyclic organic matter		0.02 - 0.044 lb/ton leaves	Based on lab tests	114
Open burning		Municipal refuse open burning	50300202	Polycyclic organic matter		0.001 - 0.0094 lb/ton waste	Based on concentration measured in smoke plume	114
Oxybisphenoxarsine and 1,3-diisocyanate production	2899	Deaeration of aqueous waste		Chloroform	67663	0.0022 lb/s	Uncontrolled	160
Oxybisphenoxarsine production	2899	Plantwide emissions		Chloroform	67663	0.0018 lb/s	Carbon adsorption	160
Paint and coating application		Entire process	402	Tetrachloroethylene	127184	2000 lb/ton PCE in paint or coating appl	Uncontrolled, based on engineering judgement	68
Paint and coating application		Entire process	40200101	Toluene	108883	2000 lb/ton used	Assume all toluene is eventually released to atmosphere	13
Paint and coating application		Entire process	402	Trichloroethylene	79016	2000 lb/ton TCE in paint or coating appl	Uncontrolled, based on engineering judgement	105
Paint and coating application	1721	End use	402	Xylenes (mixed isomers)	1330207	2000 lb/ton xylene consumed	Engineering judgement	77
Paint and coating manufacture	28	Xylene solvent	301014	Xylenes (mixed isomers)	1330207	40.4 lb/ton xylene consumed		67
Paint application		Entire process	402	Mercury	7439976	1310 lb/ton of contained Hg	Uncontrolled, based on engineering judgement	113
Paint application		Coating application of solvent-based paints	40200101	Xylenes (mixed isomers)	1330207	1740 lb/ton xylene used	Estimated	13

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	10200601	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	10200601	Polycyclic organic matter		0.649 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Natural gas combustion		Hot air furnace, home heating		Polycyclic organic matter		0.765 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion		Scotch marine, hospital heating	10200601	Polycyclic organic matter		63.8 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion		Wall space heater, home heating		Polycyclic organic matter		63.77 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion	49	Utility boiler	10100601	Ammonia	7664417	3.2 lbs/10E6 cubic feet gas burned	Sources emitting > 100 tons NH3/year, emission factor rating C	179
Natural gas combustion - commercial/institutional		Tangential or wall-fired boiler	103006	Mercury	7439976	11.363 lb/10E12 Btu	Uncontrolled emissions	213
Natural gas combustion - utility	491	Tangential-fired boiler	10100604	Mercury	7439976	2.27 lb/10E12 Btu	Controlled emissions, wet scrubber at 80% efficiency for Hg	213
Natural gas combustion - utility	491	Wall-fired boiler	10100601	Mercury	7439976	2.272 lb/10E12 Btu	Controlled emissions, wet scrubber at 80% efficiency for Hg	213
Natural gas combustion - utility	491	Tangential-fired boiler	10100604	Mercury	7439976	11.363 lb/10E12 Btu	Uncontrolled emissions, based on stack tests	213
Natural gas combustion - utility	491	Wall-fired boiler	10100601	Mercury	7439976	11.363 lb/10E12 Btu	Uncontrolled emissions, based on stack tests	213
Neoprene manufacture	2822	Dichlorobutene refining	301	1,3-Butadiene	106990	3.12 lb/ton neoprene produced	Calculated from national emissions and national capacity, mostly controlled	78
Neoprene manufacture	2822	Dichlorobutene synthesis	301	1,3-Butadiene	106990	0.6 lb/ton neoprene produced	Calculated from national emissions and national capacity, mostly controlled	78
Neoprene manufacture	2822	Equipment leak	301	1,3-Butadiene	106990	2.2 lb/ton neoprene produced	Uncontrolled, calculated from national emissions and national capacity	78
Neoprene manufacture	2822	Jet vent scrubber	301026	1,3-Butadiene	106990	0.094 lb/ton neoprene produced	Engineering Judgement	123
Neoprene manufacture	2822	Equipment leak	301018	1,3-Butadiene	106990	2.954 tons/yr	Uncontrolled, average emission factor based on 2 facilities	166
Neoprene manufacture	2822	Process vents	301018	1,3-Butadiene	106990	2.226 tons/yr	Controlled (unspecified), average emission factor based on 2 facilities	166
Neoprene manufacture	2822	Process vents	301018	1,3-Butadiene	106990	12.280 lb/ton	Uncontrolled, average emission factor based on 2 facilities	166
Neoprene manufacture	2822	Batch polykettles	301026	Chloroprene	126998	2.2 lb/ton neoprene	Engineering Judgement	123
Neoprene manufacture	2822	Blend tanks	30102614	Chloroprene	126998	0.32 lb/ton neoprene	Engineering Judgement	123

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Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
Element	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.8	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149 Ave. 50.9
Iron (Fe)	383	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

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Emission Assessment of Conventional Stationary Combustion Systems; Volume II Internal Combustion Sources

TRW, Inc, Redondo Beach, CA

Prepared for

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Feb 1979

TABLE 52. COMPARISON OF TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FUELED GAS TURBINES AND DISTILLATE OIL ENGINES

Trace Element	Mean Emission Factor, pg/J: Distillate Oil Fueled Gas Turbine	Mean Emission Factor, pg/J: Distillate Oil Reciprocating Engine
Aluminum	64	66
Antimony	9.4	12
Arsenic	2.1	2.2
Barium	8.4	14
Beryllium	0.14	0.03
Boron	28	11
Bromine	1.8	4.0
Cadmium	1.8	3.1
Calcium	330	237
Chromium	20	26
Cobalt	3.9	5.7
Copper	578	453
Iron	256	325
Lead	25	26
Magnesium	100	44
Manganese	145	16
Mercury	0.39	0.13
Molybdenum	3.6	12.5
Nickel	526	564
Phosphorus	127	97
Potassium	185	179
Selenium	2.3	2.1
Silicon	575	301
Sodium	590	1625
Tin	35	9.1
Vanadium	1.9	0.95
Zinc	294	178

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United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu) Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

APPENDIX B
CONTROL TECHNOLOGY REVIEW

B.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS regulations applicable to gas turbines 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 proposed project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-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).

The applicable NSPS for the duct burner is codified in 40 CFR Part 60 Subpart Dc. Table B-2 presents a summary of the NSPS limits. There are no quantifiable emission limits for natural gas firing.

Table B-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.

Table B-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

Source: 40 CFR Part 60 Subpart Dc.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

B.2.1 NITROGEN OXIDES

Advanced dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is technically feasible for the proposed project. The available information suggests that SCR with dry low-NO_x combustor technology or with wet injection is also technically feasible. Central Florida Power Limited Partnership believes that the advanced dry low-NO_x combustor is equivalent to the SCR technology and has several important advantages.

B.2.1.1 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 B-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.

Historically, the most stringent NO_x controls for GTs established as LAER/BACT by state agencies were selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet

Table B-3. Summary of BACT Determinations for NOx from Gas-fired Turbines (Page 1 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NO_x Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
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	Water Injection	--
O'Brian California Cogen II	CA	Jan-90	Gas Turbine	49.50 MW	--	114.6	--	--	SCR	--
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%
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	--

Table B-3. Summary of BACT Determinations for NOx from Gas-fired Turbines (Page 2 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NO_x Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
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 Cartbage	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	--	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	--
Power Development Co.	CA	Jun-87	Gas Turbine	49 MMBTU/H	--	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	--	--	--	

Table B-3. Summary of BACT Determinations for NOx from Gas-fired Turbines (Page 3 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NO_x Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
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 Refrig	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	--

injection is used initially to reduce NO_x emissions. However, advanced dry low-NO_x technology has only recently been developed and made available for gas turbines. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process.

SCR has been installed or permitted in 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 GT.

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 GTs using water injection with uncontrolled NO_x levels below 42 ppm. SCR has not been installed or permitted on simple cycle GTs.

Wet injection has been the primary method of reducing NO_x emissions from GTs. 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, GT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

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 permits and BACT determinations are 25 ppm (corrected to 15 percent O_2, dry conditions) for natural-gas firing.

B.2.1.2 Technology Description and Feasibility

Wet Injection--The injection of water or steam in the combustion zone of GTs 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 GT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

Dry Low-NO_x Combustor--In the past several years, GT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on conventional machines manufactured by GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. GE and Westinghouse have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the GT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level guaranteed by the proposed vendors for the project is 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

Selective Catalytic Reduction (SCR)--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 GTs generally are in the range of 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 B-4.

As presented in Table B-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. Optimum performance of an SCR system using 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 800°F).

Table B-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 the turbine, 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 B-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.

NO_xOUT Process--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:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

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 GT 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.

Thermal DeNO_x--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 GTs. 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. GTs 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 GTs.

Control Technologies for Duct Firing--The proposed control technology for duct firing in the HRSG will be the use of combustion controls that will limit the emissions to 0.1 lb/10^6 Btu heat input.

The applicable NSPS for the secondary HRSG are the standards promulgated for industrial-commercial-institutional steam generating units contained in 40 CFR Part 60 Subpart Db. These NSPS, for steam generators with a heat input greater than 100x10^6 Btu/hr, limit NO_x emissions from natural gas firing to 0.2 lb NO_x per 10^6 Btu heat input. BACT emission limits for duct burners located in HRSGs associated with combined cycle power plants are typically 0.1 lb NO_x per 10^6 Btu heat input.

Technology Determination--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 GT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the BACT analysis, the advanced dry low-NO_x combustor alone can achieve 25 ppm (corrected) and the SCR with dry low-NO_x combustor is capable of achieving a NO_x emission level of 9 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions). When firing oil, the emissions with SCR and wet injection would be about 15 ppm (corrected), whereas emissions with SCR and wet injection would be about 15 ppm (corrected), whereas emissions with wet injection alone would be 42 ppm (corrected). However, the SCR has an associated ammonia slip (i.e., 10 ppm).

B.2.1.3 SCR Cost Estimates

Tables B-5 and B-6 present the total capital and annualized cost for SCR, respectively.

B.2.2 CARBON MONOXIDE

B.2.2.1 Identification of CO Control Technologies

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 B-7 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in GTs. 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 GTs being evaluated, CO emissions will not exceed 15 ppmvd, corrected to dry conditions when firing natural gas under full load conditions and 50 ppmvd when firing distillate oil.

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).

For duct firing, the specific burner design to control NO_x emissions has commonly established the ability of the burner to meet CO limits. Recent BACT decisions for duct firing have ranged from 0.14 lb/10^6 Btu for Tropicana Products, Inc. to 0.2 lb/10^6 Btu for the Lake and Pasco Cogen

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Direct Capital Costs</u>		
SCR Associated Equipment	725,000	Developed from manufacturer budget quotations[a]
Ammonia Storage Tank	250,000	Developed from manufacturer budget quotations[b]
HRSG Modification	440,000	Developed from manufacturer budget quotations[c]
<u>Indirect Capital Costs</u>		
Installation and Foundation (Includes Contractor Fee)	1,298,300	45% of SCR associated equipment and catalyst[d]
Engineering, Erection Supervision, Startup, and O&M Training	487,300	10% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG costs, installation labor.[e]
Project Support	268,000	5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs, and installation labor.[f]
Ammonia Emergency Prepardness Program	20,300	Engineering estimate
Liability Insurance	26,800	0.5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs and installation labor.
Interest During Construction	851,300	15% of all direct and indirect capital costs, including catalyst cost[g]
Contingency	929,800	25% of all capital costs[h]
<u>Total Capital Costs</u>	5,296,800	Sum of all capital costs

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Annualized Capital Costs	622,200	Capital recovery of 10% over 20 years, 11.74% per year[i]
Recurring Capital Costs		
SCR Catalyst (Materials and Labor)	2,160,000	Developed from manufacturer budget quotations[j]
Contingency	540,000	25% of recurring capital costs[k]
Total Recurring Capital Costs	2,700,000	Sum of recurring capital costs
Annualized Recurring Capital Costs	1,085,700	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 B-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 \$100.7 per 1,000 lb/hr mass flow at normal operating conditions (i.e., ~3,600,000 lb/hr).

   $\$100.7 \times 3{,}600\ 10^3$ lb/hr = \$362,500

2. Control system costs = \$362,500

   Total is \$725,000

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Footnotes for Table B-5 (continued)

b. Ammonia tank size is based on SCR size as follows:

$69.45/1,000 lb mass flow x 3,600 x 10^3 lb/hr = $250,000

c. HRSG modifications based on mass flow at $122.2 per 1,000 lb mass flow.

$122.22/$10^3$ lb x 3,600 x 10^3 lb/hr = $440,000

d. From EPA OAQPS cost control manual

($725,000 + $2,160,000) x 0.45 = $1,298,300

e. From EPA OAQPS cost control manual

($725,000 + $250,000 + $2,160,000 + $440,000 + $1,298,300) x 0.10

= $487,300

f. Engineering estimate; same as engineering costs except use 0.005.

g. From OAQPS cost control manual and engineering estimate.

0.15 x ($725,000 + $250,000 + $440,000 + $1,298,300 + $487,300

+ $268,000 + $20,300 + $26,800 + $2,160,000) = $851,300

h. From EPA OAQPS cost control manual and engineering estimate

0.20 x ($725,000 + $250,000 + $440,000 + $1,298,300 + $487,300

+ $268,000 + $20,300 + $26,800 + $851,300) - (0.25 x 0.30

x $2,160,000)

= $929,800; note that the (0.25 x 0.30 x $2,160,000)

removes contingency for catalyst.

i. OAQPS cost control manual; standard statistical tables for 10% interest over 20 years

$5,296,800 x 0.1174 = $622,200

j. Developed from manufacturer data at $0.6/lb mass flow:

$0.6 x 3,600,000 = $2,160,000

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Footnotes for Table B-5 (continued)

k. Same rationale as h:

0.25 x $2,160,000 = $622,200

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 $2,700,000 = $1,085,700

Table B-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	31,200	16 hours/week @ $25/hour[a]
Ammonia	51,500	$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	84,600	Capital recovery (11.74%/year) for 1/3 of catalyst cost[d]
Catalyst Disposal Cost	100,000	Engineering estimate[e]
Contingency	83,100	25% of indirect costs[f]
Energy Costs		
Electrical	35,000	80 kWh/hr; $0.05/kWh[g]
Heat Rate Penalty	321,900	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh[h]
MW Loss Penalty	432,000	207 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted[i]
Fuel Escalation Costs	162,300	Real cost increase of fuel[j]
Contingency	129,800	25% of energy costs; excludes fuel escalation[k]
Total Direct Annual Costs	1,439,500	Sum of all direct annual costs

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Indirect Annual Costs		
Overhead	57,100	60% of ammonia and 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)[l]
Property Taxes and Insurance	159,900	2% of total capital costs[m]
Annualized Capital Costs	622,200	Capital recovery of 10% over 20 years, 11.74% per year (from Table B-5)
Recurring Capital Costs	1,085,700	Capital recovery of 10% over 3 years, 40.21% per year (from Table B-5)
Total Indirect Annual Costs	1,924,900	Sum of all indirect annual costs
Total Annual Costs	3,364,400	Total annualized cost[n]
Cost Effectiveness ($/ton NO_x)	7,370	Total annual costs divided by tons NO_x removed[o]

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.

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Footnotes for Table B-6

Note: all calculations rounded to nearest 100

a. Engineering Estimate:

24 hours/week x 52 weeks/year x \$25/hour = \$31,200

b. Delivered cost of ammonia at \$300/ton

464 TPY removed x \$300 x 17/46 (molecular weight of ammonia to NO_x)

= 51,500

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.

\$2,160,000 x 0.1174 (20 years @ 10 percent) ÷ 3 = \$84,600

e. Estimated as \$27.77/1,000 lb mass flow; based on catalyst volume.

\$27.77 x 3,600 (1,000 lb mass flow) = \$100,000

f. OAQPS cost control manual background documents

0.25 x (\$31,200 + \$51,500 + \$8,100 + \$84,600 + \$100,000) = \$83,100

g. 80 kWh/hr from SCR manufacturer; \$0.05/kWh is cost of estimated energy:

80 kWh/hr x \$8,760 hr/yr x \$0.08/kWh = \$35,000

h. 4" back pressure from SCR manufacturer; 0.8 percent energy loses from general CT performance curver; 147 MW power rating at ISO (59°F) conditions.

147 MW x 0.005 x 8,760 hrs/yr x 1,000 kW/mw x \$0.05/kWh = \$321,900

i. 3 days required to change catalyst or maintenance; saving in gas usage subtracted

207 MW x 3 days x 24 hours x \$0.05/kWh x 1,000 mwh - (1,450 x 10^6 Btu/hr

x 3 days x 24 hours x \$3/10^6 Btu) = \$432,000

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Footnotes for Table B-6 (continued)

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 + $321,900) = $162,300

k. OAQPS cost control manual background documents

0.25 x ($35,000 + $321,900 + $162,300) = $129,800

l. 0.6 ($51,500 + 1.15 x $31,200) + 0.15 x $31,200 = $57,100

m. From OAQPS cost control manual

0.02 x ($5,296,800 + $2,700,000) = $159,900

n. Total direct annual costs plus total indirect annual costs:

$1,439,500 + $1,924,900 = $3,364,400

o. Cost effectiveness is total annual costs divided by the tons removed (702.11 tons/yr x 0.65 = 456.4 tons/yr):

$3,364,400 ÷ 456.4 = $7,370/ton of NO_x removed

Table B-7. 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	Efficiency (%)
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	1400 MMBtu/hr	--	--	261	30	Combustion control	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 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	--
Indac/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	--
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	--		--	Combustion Control	--

Table B-7. 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	Efficiency (%)
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	--	--	--	--	--
Simpson Paper Co.	CA	Jun-87	Gas Turbine	49.50 MW	--	54.25	--	55 @ 15% O_2	Combustion Controls	--
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	Combustion Control	--
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	--	--	--

Limited projects. The proposed CO BACT emission limit for the project is 0.1 lb/10^6 Btu.

B.2.2.2 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 GTs, the oxidation catalyst can be located directly after the GT. 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.

Oxidation catalysts have not been used on fuel-oil-fired GTs 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.

B.2.2.3 Oxidation Catalyst Costs

Table B-8 presents the capital and annualized cost for an oxidation catalyst.

Table B-8. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	138,750	Manufacture Estimate - $257 per lb/hr mass flow; 15% for equipment
2. Exhaust Modification	250,000	Engineering Estimate
3. Installation	293,750	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	88,125	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	117,500	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	58,750	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	23,500	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	242,590	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	299,880	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	1,512,850	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	177,700	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	786,250	Manufacture Estimate - $257 per lb/hr mass flow; 85% of catalyst
B. Contingency	196,560	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	982,810	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	395,200	Capital Recovery of 10% over 20 years
III. ANNUALIZED COST		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,980	4 hours/week, 52 weeks/year, $25/hour and 15% supervisor cost
2. Maintenance	12,480	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	30,280	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
B. ENERGY COSTS		
1. Heat Rate Penalty	128,800	0.2% heat rate penalty. $50/MW energy loss
2. MW Loss Penalty (catalyst changeout)	63,000	Loss of 147 MW for one day; cost of natural gas at $3/10^6 Btu deducted from cost
3. Fuel Escalation Costs	58,500	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	62,600	25% of energy costs
C. INDIRECT:		
1. Overhead	11,080	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	24,960	1% of Total and Recurring Capital Cost
3. Insurance	24,960	1% of Total and Recurring Capital Cost
4. Administration	49,910	2% of Total and Recurring Capital Cost
Annualized Capital Costs	177,700	
Annualized Recurring Capital Costs	395,200	
TOTAL ANNUALIZED COSTS	1,045,936	Sum of Operating and Maintenance and Annualized Capital Costs
Cost Effectiveness ($/ton NO_x removed)	14,756	Total annualized cost divided by CO removal (71 TPY; gas and oil to 10 ppmvd)

Note: All calculations using machine performance were based on 72°F conditions.
Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

APPENDIX C

SUMMARY OF GENERIC MODELING IMPACTS

ISCST2 OUTPUT FILE NUMBER 1 :DTGEN180.082
ISCST2 OUTPUT FILE NUMBER 2 :DTGEN180.083
ISCST2 OUTPUT FILE NUMBER 3 :DTGEN180.084
ISCST2 OUTPUT FILE NUMBER 4 :DTGEN180.085
ISCST2 OUTPUT FILE NUMBER 5 :DTGEN180.086
First title for last output file is: 1986 DESTEC / GENERIC / 10 G/S / NAT GAS VELOCITIES
Second title for last output file is: RUN 180 FOOT STACK / 70,100% LOADS; 27, 97 oF

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: G10027					
Annual					
	1982	0.0824	240.	4000.	--
	1983	0.0661	70.	2000.	--
	1984	0.0824	240.	4000.	--
	1985	0.0977	70.	2000.	--
	1986	0.1144	90.	2000.	--
HIGH 1-Hour					
	1982	9.8350	120.	300.	82011413
	1983	10.3219	300.	300.	83022713
	1984	11.7771	100.	300.	84032908
	1985	9.8844	130.	1000.	85060311
	1986	7.4769	90.	1000.	86080111
HSH 1-Hour					
	1982	9.6327	120.	300.	82011415
	1983	7.9956	70.	1000.	83081011
	1984	6.6240	10.	1000.	84090511
	1985	6.6217	250.	1000.	85090812
	1986	6.6470	50.	1000.	86090712
HIGH 3-Hour					
	1982	6.4892	120.	300.	82011415
	1983	4.4990	260.	1000.	83081912
	1984	4.5660	270.	1000.	84072512
	1985	4.4667	80.	2000.	85101315
	1986	4.6515	90.	1000.	86080112
HSH 3-Hour					
	1982	3.5158	250.	2000.	82090612
	1983	3.8249	40.	1500.	83090515
	1984	3.7363	260.	1000.	84072512
	1985	4.0633	80.	2000.	85042415
	1986	4.4275	90.	1000.	86071315
HIGH 8-Hour					
	1982	2.6729	240.	3000.	82050316
	1983	2.6045	50.	2000.	83083016
	1984	2.9070	250.	2000.	84061216
	1985	2.7723	90.	3000.	85060216
	1986	2.7357	90.	2000.	86100516
HSH 8-Hour					
	1982	2.2784	0.	2000.	82082716
	1983	2.2837	240.	3000.	83101616
	1984	2.1577	90.	2000.	84061916
	1985	2.3292	90.	2000.	85062816
	1986	2.7190	90.	2000.	86081816
HIGH 24-Hour					
	1982	1.1386	240.	2000.	82082924
	1983	1.1048	50.	2000.	83083024
	1984	1.0539	90.	2000.	84060224
	1985	1.0958	90.	3000.	85060224
	1986	1.2084	90.	2000.	86081824
HSH 24-Hour					
	1982	1.0150	0.	2000.	82082724
	1983	0.8381	240.	3000.	83101624
	1984	0.8568	90.	2000.	84083124

	1985	0.8568	80.	2000.	85060424
	1986	1.0071	90.	2000.	86072024
SOURCE GROUP ID: G10097					
Annual					
	1982	0.0969	240.	4000.	--
	1983	0.0758	70.	2000.	--
	1984	0.0935	240.	4000.	--
	1985	0.1130	70.	2000.	--
	1986	0.1330	90.	2000.	--
HIGH 1-Hour					
	1982	13.3253	130.	300.	82011414
	1983	12.8410	290.	300.	83022712
	1984	15.0724	220.	300.	84081704
	1985	10.8222	120.	300.	85021217
	1986	9.0647	10.	2000.	86121212
HSH 1-Hour					
	1982	11.8295	120.	300.	82011415
	1983	8.6258	290.	300.	83022709
	1984	12.5402	130.	300.	84022811
	1985	10.6668	120.	300.	85021214
	1986	7.1840	350.	1000.	86082212
HIGH 3-Hour					
	1982	8.1956	120.	300.	82011415
	1983	4.7802	260.	1000.	83081912
	1984	8.1705	120.	300.	84032912
	1985	6.8721	120.	300.	85021215
	1986	4.8852	90.	1000.	86080112
HSH 3-Hour					
	1982	3.9824	250.	2000.	82090612
	1983	4.0280	330.	2000.	83090412
	1984	6.0423	120.	300.	84032915
	1985	4.6637	80.	2000.	85042415
	1986	4.8608	90.	1000.	86071315
HIGH 8-Hour					
	1982	3.0734	120.	300.	82011416
	1983	3.0577	290.	300.	83022716
	1984	5.3298	120.	300.	84032916
	1985	3.1103	90.	2000.	85060216
	1986	3.1567	90.	2000.	86100516
HSH 8-Hour					
	1982	2.6291	0.	2000.	82082716
	1983	2.5936	240.	3000.	83061016
	1984	2.4770	90.	2000.	84061916
	1985	2.6613	90.	2000.	85062816
	1986	3.0679	90.	2000.	86081816
HIGH 24-Hour					
	1982	1.3406	240.	3000.	82050324
	1983	1.2329	50.	2000.	83083024
	1984	1.8636	130.	300.	84022824
	1985	1.5056	120.	300.	85021224
	1986	1.3635	90.	2000.	86081824
HSH 24-Hour					
	1982	1.1973	240.	2000.	82050324
	1983	0.9731	240.	3000.	83101624
	1984	0.9955	90.	2000.	84083124
	1985	0.9538	90.	3000.	85042824
	1986	1.1184	90.	2000.	86072024
SOURCE GROUP ID: G7027					
Annual					
	1982	0.1116	240.	4000.	--
	1983	0.0883	70.	2000.	--
	1984	0.1092	240.	3000.	--
	1985	0.1323	70.	2000.	--
	1986	0.1571	90.	2000.	--
HIGH 1-Hour					
	1982	16.1083	130.	300.	82011414

	1983	15.7330	290.	300.	83022712
	1984	17.9262	220.	300.	84081704
	1985	13.4108	120.	300.	85021217
	1986	10.9461	120.	300.	86012714
HSH 1-Hour					
	1982	14.1934	120.	300.	82011415
	1983	11.8351	110.	300.	83032416
	1984	15.3055	130.	300.	84022811
	1985	13.3936	120.	300.	85021214
	1986	8.0409	230.	700.	86082313
HIGH 3-Hour					
	1982	9.8242	120.	300.	82011415
	1983	7.3016	110.	300.	83032418
	1984	14.0222	120.	300.	84032912
	1985	9.4742	120.	300.	85021215
	1986	5.6045	10.	1500.	86063012
HSH 3-Hour					
	1982	6.5808	120.	300.	82011418
	1983	6.9996	110.	300.	83020315
	1984	7.7288	120.	300.	84032915
	1985	5.4027	80.	2000.	85042415
	1986	5.1673	90.	1000.	86080112
HIGH 8-Hour					
	1982	4.7554	120.	300.	82011416
	1983	4.5340	110.	300.	83020316
	1984	10.1898	120.	300.	84032916
	1985	4.4556	120.	300.	85021216
	1986	3.6719	90.	2000.	86100516
HSH 8-Hour					
	1982	3.3172	0.	2000.	82060616
	1983	2.8566	240.	3000.	83061016
	1984	3.0867	130.	300.	84032916
	1985	3.0749	90.	2000.	85062816
	1986	3.4962	90.	2000.	86081816
HIGH 24-Hour					
	1982	2.0506	120.	300.	82011424
	1983	1.5113	110.	300.	83020324
	1984	3.5757	120.	300.	84032924
	1985	2.3133	120.	300.	85021224
	1986	1.5674	90.	1500.	86081824
HSH 24-Hour					
	1982	1.4350	240.	2000.	82050324
	1983	1.1894	110.	300.	83032424
	1984	1.8546	120.	300.	84022824
	1985	1.1567	80.	1500.	85101124
	1986	1.2771	90.	2000.	86072024
SOURCE GROUP ID: G7097					
Annual					
	1982	0.1217	240.	3000.	--
	1983	0.0972	90.	2000.	--
	1984	0.1192	240.	3000.	--
	1985	0.1440	70.	2000.	--
	1986	0.1734	90.	2000.	--
HIGH 1-Hour					
	1982	18.1638	130.	300.	82011414
	1983	17.8869	290.	300.	83022712
	1984	19.9664	220.	300.	84081704
	1985	15.4725	120.	300.	85021214
	1986	12.6341	120.	300.	86012714
HSH 1-Hour					
	1982	15.9307	120.	300.	82011415
	1983	13.9038	110.	300.	83031015
	1984	17.3627	130.	300.	84022811
	1985	15.3647	120.	300.	85021217
	1986	9.0998	230.	700.	86082313
HIGH 3-Hour					

	1982	11.0181	120.	300.	82011415
	1983	8.4475	110.	300.	83032418
	1984	16.1132	120.	300.	84032912
	1985	10.9431	120.	300.	85021215
	1986	6.1693	10.	1500.	86063012
HSH 3-Hour					
	1982	7.6627	120.	300.	82011418
	1983	8.2503	110.	300.	83020315
	1984	12.7449	130.	300.	84022806
	1985	8.3035	120.	300.	85021218
	1986	5.3299	90.	1000.	86080112
HIGH 8-Hour					
	1982	5.3772	120.	300.	82011416
	1983	5.3570	110.	300.	83020316
	1984	11.7426	120.	300.	84032916
	1985	5.8617	110.	300.	85021208
	1986	3.9786	90.	2000.	86100516
HSH 8-Hour					
	1982	3.5715	0.	2000.	82060616
	1983	3.0326	240.	2000.	83101616
	1984	6.1273	130.	300.	84022808
	1985	3.3268	90.	2000.	85062816
	1986	3.8359	90.	1500.	86100516
HIGH 24-Hour					
	1982	2.3351	120.	300.	82011424
	1983	1.7857	110.	300.	83020324
	1984	5.0949	130.	300.	84022824
	1985	3.5979	120.	300.	85021224
	1986	1.7314	90.	1500.	86081824
HSH 24-Hour					
	1982	1.5969	240.	2000.	82050324
	1983	1.3793	110.	300.	83032424
	1984	2.4163	120.	300.	84022824
	1985	1.2621	80.	1500.	85060424
	1986	1.3808	90.	2000.	86072024

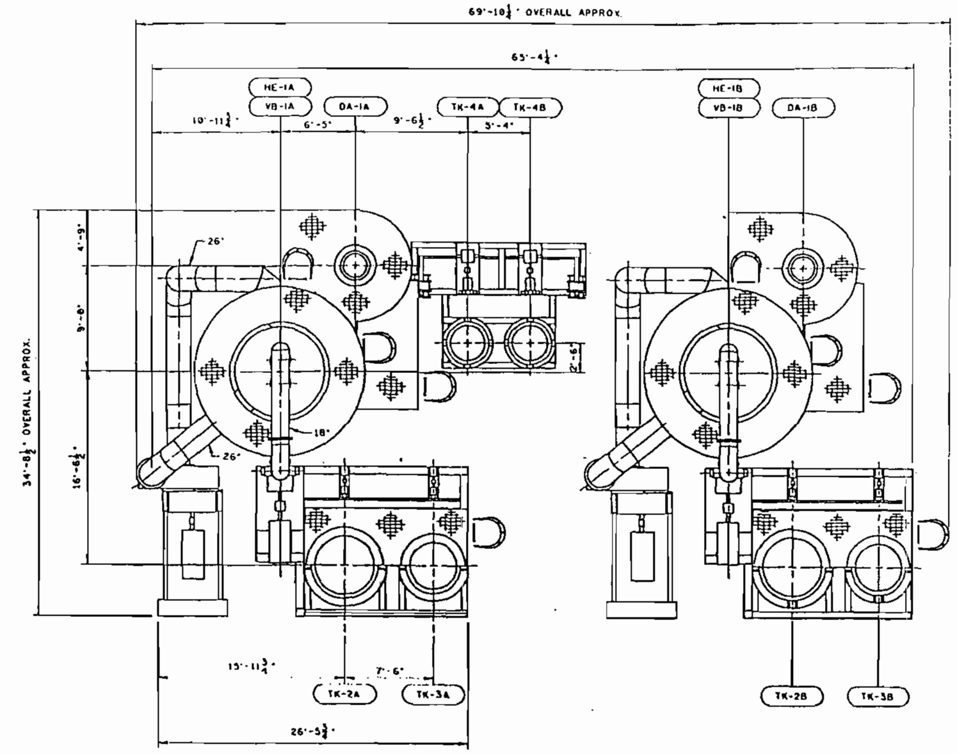
ISCST2 OUTPUT FILE NUMBER 1 :DTCLASS1.082
ISCST2 OUTPUT FILE NUMBER 2 :DTCLASS1.083
ISCST2 OUTPUT FILE NUMBER 3 :DTCLASS1.084
ISCST2 OUTPUT FILE NUMBER 4 :DTCLASS1.085
ISCST2 OUTPUT FILE NUMBER 5 :DTCLASS1.086

First title for last output file is: 1986 DESTEC / CLASS 1 / 10 G/S / NAT GAS VELOCITIES

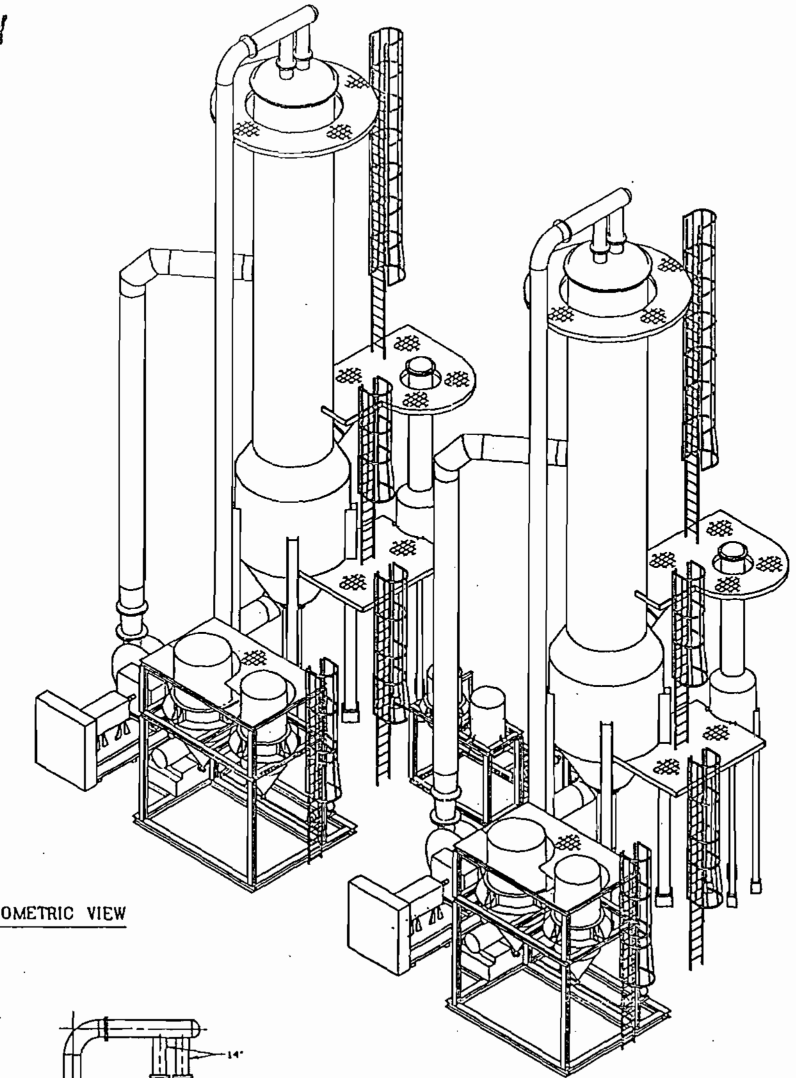
Second title for last output file is: RUN 180 FOOT STACK / 70,100% LOADS; 27, 97 oF

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: G10027					
Annual					
	1982	0.00590	340300.	3165700.	--
	1983	0.00440	340300.	3165700.	--
	1984	0.00260	340300.	3165700.	--
	1985	0.00380	343700.	3178300.	--
	1986	0.00400	343700.	3178300.	--
HIGH 24-Hour					
	1982	0.06808	340300.	3165700.	82072924
	1983	0.07004	340300.	3165700.	83090424
	1984	0.06539	342000.	3174000.	84041924
	1985	0.06348	341100.	3183400.	85110724
	1986	0.08764	340700.	3171900.	86121024
HSH 24-Hour					
	1982	0.06578	340300.	3165700.	82062524
	1983	0.06355	340300.	3165700.	83051524
	1984	0.04801	334000.	3183400.	84052424
	1985	0.04837	343700.	3178300.	85032924
	1986	0.07127	340300.	3169800.	86031124
SOURCE GROUP ID: G10097					
Annual					
	1982	0.00600	340300.	3165700.	--
	1983	0.00450	340300.	3165700.	--
	1984	0.00260	340300.	3165700.	--
	1985	0.00400	343700.	3178300.	--
	1986	0.00420	343700.	3178300.	--
HIGH 24-Hour					
	1982	0.07222	340300.	3165700.	82072924
	1983	0.07289	340300.	3165700.	83090424
	1984	0.06954	342000.	3174000.	84041924
	1985	0.07250	343700.	3178300.	85011924
	1986	0.08982	340700.	3171900.	86121024
HSH 24-Hour					
	1982	0.06999	340300.	3165700.	82062524
	1983	0.06648	340300.	3167700.	83120224
	1984	0.05030	334000.	3183400.	84052424
	1985	0.06653	341100.	3183400.	85011924
	1986	0.07392	340300.	3169800.	86031124
SOURCE GROUP ID: G7027					
Annual					
	1982	0.00630	340300.	3165700.	--
	1983	0.00470	340300.	3165700.	--
	1984	0.00290	340300.	3165700.	--
	1985	0.00420	343700.	3178300.	--
	1986	0.00430	340300.	3165700.	--
HIGH 24-Hour					
	1982	0.07699	340300.	3165700.	82072924
	1983	0.07614	340300.	3165700.	83090424
	1984	0.07388	342000.	3174000.	84041924
	1985	0.07551	343700.	3178300.	85011924
	1986	0.09225	340700.	3171900.	86121024
HSH 24-Hour					
	1982	0.07486	340300.	3165700.	82062524

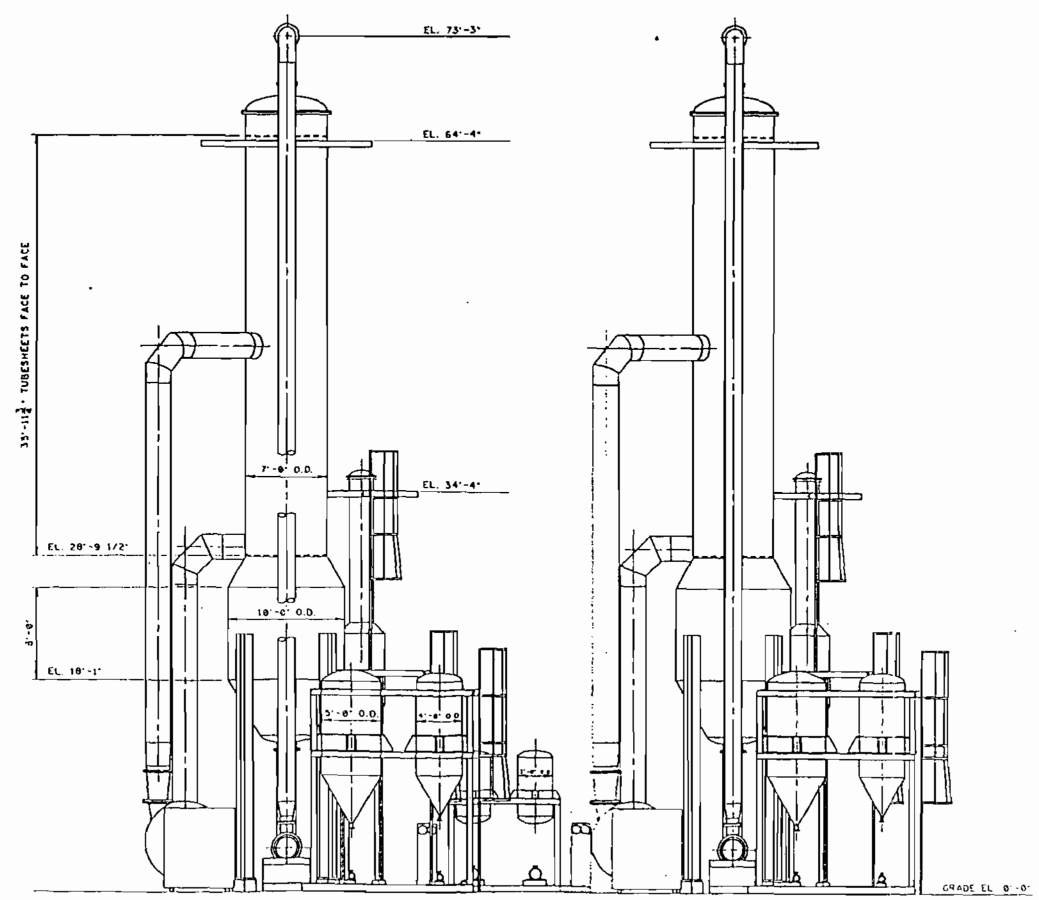
	1983	0.07023	340300. 3167700.	83120224
	1984	0.05291	334000. 3183400.	84052424
	1985	0.06909	341100. 3183400.	85011924
	1986	0.07686	340300. 3169800.	86031124
SOURCE GROUP ID:	G7097			
Annual				
	1982	0.00640	340300. 3165700.	--
	1983	0.00480	340300. 3165700.	--
	1984	0.00300	340300. 3165700.	--
	1985	0.00430	343700. 3178300.	--
	1986	0.00450	340300. 3165700.	--
HIGH 24-Hour				
	1982	0.07987	340300. 3165700.	82072924
	1983	0.07879	340300. 3165700.	83090424
	1984	0.07656	342000. 3174000.	84041924
	1985	0.07748	343700. 3178300.	85011924
	1986	0.09369	340700. 3171900.	86121024
HSH 24-Hour				
	1982	0.07781	340300. 3165700.	82062524
	1983	0.07274	340300. 3167700.	83120224
	1984	0.05448	334000. 3183400.	84052424
	1985	0.07076	341100. 3183400.	85011924
	1986	0.07864	340300. 3169800.	86031124



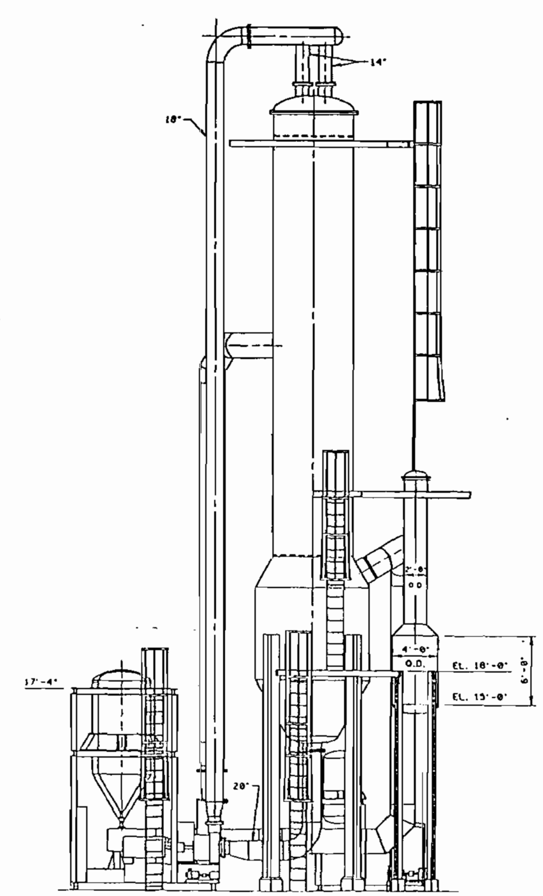
PLAN VIEW



ISOMETRIC VIEW



ELEVATION VIEW



RIGHT SIDE VIEW

NOTES

1. ALL DIMENSIONS ARE APPROXIMATE.
2. HANDRAILS NOT SHOWN FOR CLARITY.
3. EXCLUDING OVERALL DIMENSIONS, ALL DIMENSIONS ARE TYPICAL FOR TRAINS "A" & "B".

REV.	DATE	BY	CHK'D	APVD	DESCRIPTION

DRAWING TITLE
GENERAL ARRANGEMENT
ZERO LIQUID DISCHARGE SYSTEM

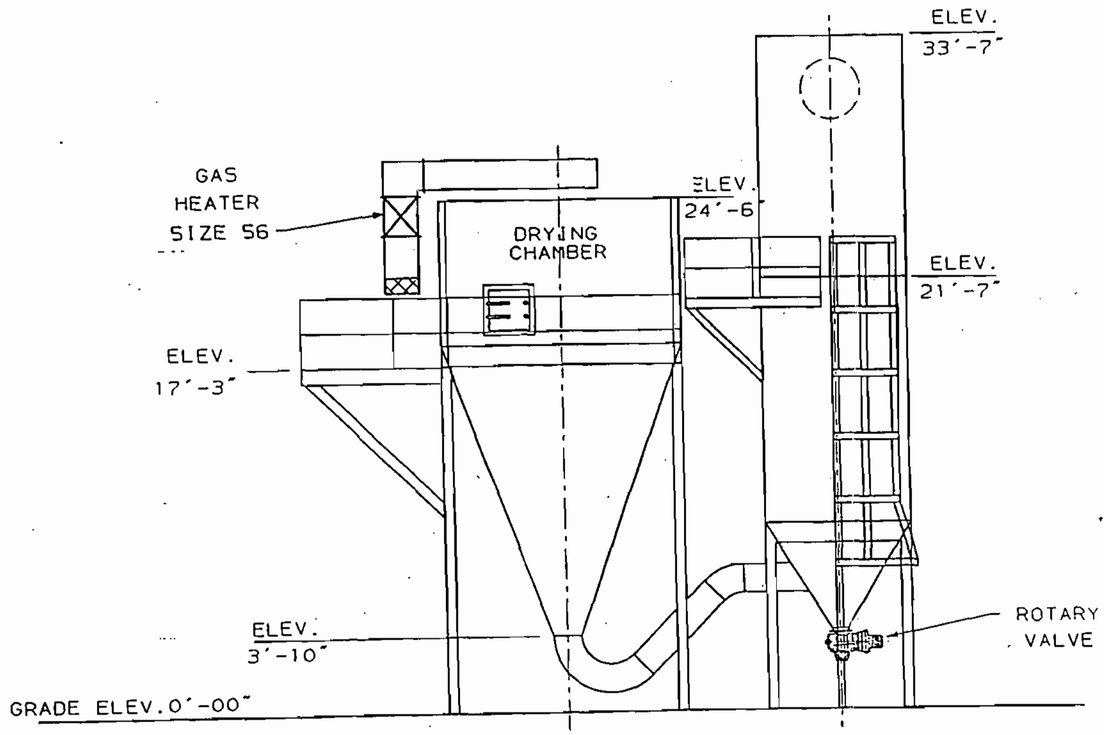
CUSTOMER
DESTEC ENGINEERING, INC.
HOUSTON, TEXAS

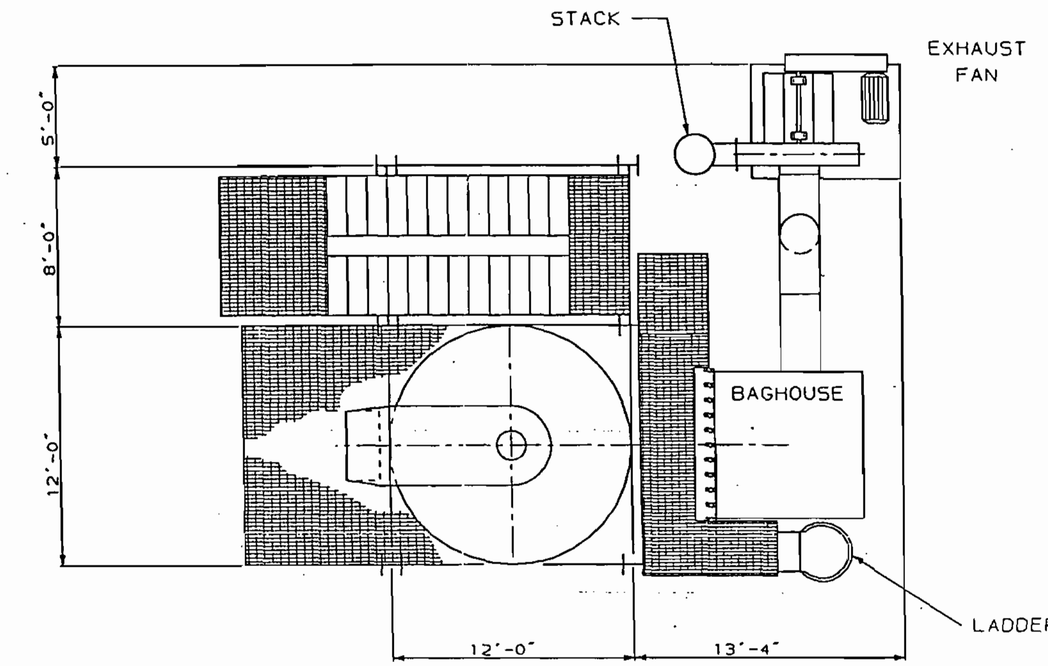
ENGINEER

UNITECH
Division of The Graver Company

DRWN.	MSM		UNITECH NO. 92138	DRAWING NUMBER E-92138-6 — REV. 0
CHK'D.				
APVD.			SCALE 3/16"=1'-0"	

DO NOT SCALE THIS DRAWING USE DIMENSIONS ONLY





01-27-93 12:00:50

REV.	DATE	BY	CHK'D	APVD	DESCRIPTION

DRAWING TITLE
GENERAL ARRANGEMENT
DRYING SYSTEM

CUSTOMER
DESTEC ENGINEERING, INC.
HOUSTON, TEXAS

ENGINEER

UNITECH
Division of The Graver Company

DRWN.	MSM	01-27-93	UNITECH NO. 92138	DRAWING NUMBER	REV.
CHK'D.				D-92138-7	Ø
APVD.			SCALE NONE		

DO NOT SCALE THIS DRAWING USE DIMENSIONS ONLY

DESTEC
OPERATING COMPANY

TIGER BAY COG...
3219 STATE RD., 630 ...
FORT MEADE, FL 33841
(813) 285-1200 (813) 285-1206

January 24, 1996

Mr. Al Linero
Florida Department of Environmental Protection
Air Resource Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

RE: ***Tiger Bay Limited Partnership***
Permit Number: AC53-214903
Facility ID: AIRS-1050223

Dear Mr. Linero,

It was a pleasure meeting with you and your staff on January 23, 1996 to discuss Specific Condition No.5.b of Tiger Bay Limited Partnership's ("Tiger Bay") air quality permit.

Based on our discussion and a review of potential operating conditions, Tiger Bay would like to propose the following amendment to Specific Condition No.5.b:

> "The permitted materials and utilization rates for the combined cycle gas turbine system shall be as stated in the application. The operating parameters include, but are not limited to: b) The maximum heat input of ~~1,614.8 MMBtu/hr (LHV) at 27°F~~ 1,710 MMBtu/hr and at base load for natural gas."

Again, thank you very much for your time. It was a pleasure meeting you. If you should have any questions or require further information please do not hesitate to contact me at (941) 285-1200 or Ms. Jeanne Benedetti, Senior Environmental Engineer at (713) 735-4568.

Very truly yours,

Jeffrey J. Fassett
Senior Plant Engineer

JJF:tma

cc: Jeanne Bennedette / Destec
F39.2.6