FORT PIERCE UTILITIES AUTHORITY
UTILITIES ENGINEERING DEPARTMENT
P. O. BOX 3191
FORT PIERCE, FLORIDA 33448
(305) 464-5600

LETTER OF TRANSMITTAL

DATE	JOB NO.
10-30-87	

ATTENTION

RE: Application to Construct Air Pollution Source @ Combined Cycle Power Plant - Ft. Pierce, FL.

TO Clair H. Fancy, P.E. Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulations
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, FL 32301

WE ARE SENDING YOU ☒ Attached ☐ Under separate cover via ______ the following items:

☐ Shop drawings ☐ Prints ☐ Plans ☐ Samples ☐ Specifications

☐ Copy of letter ☐ Change order ☐ ______

COPIES	DATE	NO.	DESCRIPTION
4	10-28-87		Subject Report
1	10-30-87		Check for $1,000

THESE ARE TRANSMITTED as checked below:

☐ For approval ☐ Approved as submitted ☐ Resubmit ____ copies for approval

☒ For your use ☐ Approved as noted ☐ Submit ____ copies for distribution

☐ As requested ☐ Returned for corrections ☐ Return ____ corrected prints

☐ For review and comment ☐ ______

☐ FOR BIDS DUE ______ 19____ ☐ PRINTS RETURNED AFTER LOAN TO US

REMARKS ______

COPY TO ______

SIGNED: Victor F. Garrions P.E.

VENDOR COPY

PURCHASE ORDER

FT. PIERCE UTILITIES AUTHORITY

P.O. BOX 3191
FT. PIERCE, FLORIDA 33454
PHONE (305) 464-5600

ORDER NO. 21171
Date 10-30-87

2090

BILL TO →

FOLD →

SHIP TO →

☐ Ft. Pierce Utilities - Warehouse
25th Street & Florida Avenue

☐ Ft. Pierce Utilities — Warehouse
Savannah Road

☐

Not to exceed $5000

Bureau of Air Quality Management
Fla. Dept. of Environmental Regulation
2600 Blair Stone Road -Twin Towers Bldg.
Tallahassee, FL 32301

DIRECTOR OF UTILITIES

REQUIRED DELIVERY DATE:

FOLD →

QUANT.	ACCOUNT CODE	CATALOG NO. & DESCRIPTION	UNIT PRICE	TOTAL
		Permit Application Fee		1,000.00
		for No. 9 Combined Cycle Gas		
		Turbine.		

1987 NOV -2 AM 11:19
DER - MAIL ROOM
RECEIVED

☐ Verbal Quote ☐ Informal Written Quote (U.A. No. ______) ☐ Formal Written Quote (U.A. Bid No. ______)

TERMS & CONDITIONS

1. C.O.D Shipments are not accepted under any circumstance.
2. Prepay & add freight on all orders which are not specified-F.O.B. Ft. Pierce, Florida.
3. Invoices must bear purchase order number.
4. The Ft. Pierce Utilities Authority is exempt from payment of Excise Tax in Accordance with Title 26 United States Code Annotated, and is exempt from the payment of Fla. State Tax.

TAX EXEMPT CERTIFICATE # 66-02-05279-84

1031

Federal Express
053456240
PM
10.30.87
Ft. Pierce, FL

File Copy

APPLICATION TO CONSTRUCT

AIR POLLUTION SOURCE

COMBINED CYCLE POWER PLANT

FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA

Ft. Pierce Utility Authority
AC 56-141460

Date Complete: Dec. 18, 1987
TE/PD Mailed: Feb. 12, 1988 } 57 days
Proof of P/N Rec'd: Feb. 22, 1988 } 14 day
Mar. 06, 1988 P/N Req.
Mar. 07, 1988 = 58 day
Mar. 31, 1988 } 82 days
Day 90 = Apr. 08, 1988

Prepared by:

ENVIRONMENTAL SCIENCE AND ENGINEERING, INC.

October 28, 1987

Sub code - 01

2090

WATER

ELECTRIC

GAS

SEWER

206 S. SIXTH STREET • P. O. BOX 3191 • FORT PIERCE, FLORIDA 33450 • PHONE (305) 464-5600

October 28, 1987

DER

NOV 2 1987

BAQM

Clair H. Fancy, P.E., Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulation
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32301

Subject: **Construction Permit Application**
No. 9 Combined Cycle Gas Turbine

Dear Mr. Fancy:

The Fort Pierce Utilities Authority is currently upgrading and modernizing the H.D. King Electric Generating Plant. The major feature of this modernization program is construction of the new No. 9 Combined Cycle Gas Turbine. The installation will combine a gas turbine generator rated at 23.4 megawatts with a waste heat recovery steam generator which will repower the existing No. 5 power generator (8.2 megawatts).

The new facility will be more efficient and will require less fuel per kilowatt-hour to operate than the existing No. 7 and No. 8 Boilers. Consequently, we plan to maximize the operation of Unit No. 9 and curtail the operation of the older boilers.

We are very anxious to modernize our plant and request that you expedite the processing of this permit application package.

Very truly yours,

Harry Schindehette, P.E.
Director of Utilities

HS/cdb

Copied Teresa Heron } 11/4/87 mo
I Goldman } 11/13/87 mo 2nd time.

TABLE OF CONTENTS

COMBINED CYCLE POWER PLANT

FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA

11/13/87

Contacted I. Goldman and asked if he had received this permit, he said they do not have a copy in house so I put one in the mail to him on Nov. 13, 1987 (MP)

ESE

AN RSH COMPANY

ENVIRONMENTAL SCIENCE
AND ENGINEERING, INC.

October 28, 1987

Clair H. Fancy, P.E., Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulation
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32301

Subject: **Application to Construct Air Pollution Source**
No. 9 Combined Cycle Gas Turbine
Fort Pierce Utilities Authority
Fort Pierce, Florida

Dear Mr. Fancy:

We have prepared this construction permit application package on behalf of the Fort Pierce Utilities Authority (FPUA). When issued, the permit will allow FPUA to upgrade the H.D. King Electric Generating Plant by constructing a new combined cycle unit.

Enclosed is a check for $1,000.00 payable to the Florida Department of Environmental Regulation as required by FAC 17-4.050(4)(a)1, for the application review fee.

This application package contemplates the construction of a combined cycle unit consisting of:

- A gas turbine and generator (23.4 megawatts),
- A waste heat recovery steam generator (HRSG), and
- All auxiliary equipment.

The waste heat recovery steam generator will repower the existing No. 5 generator (8.2 megawatts) as well as provide steam injection to control NO_x emissions from the gas turbine.

The combined cycle unit is more efficient and will require less fuel per kilowatt-hour to operate. Use of the more efficient No. 9 generator will allow FPUA to substantially reduce the operating hours of the less efficient Units 7 and 8.

Since the project is a modification of a major source in an attainment area, we have appended a contemporaneous emissions calculation to this permit application package. By using the increased efficiency from the new combined cycle unit, the steam injection for control of NO_x

904/739-2007 • 6737 Southpoint Drive, South • Post Office Box 4943 • Jacksonville, Florida 32201

emissions and a reduction in operating hours for Units 7 and 8, it is clear that the projected emissions will not exceed any of the significant emissions increase limits. Consequently, a new source review is not required.

We are understandably anxious to proceed on this project and will appreciate any effort by your office to expedite its processing.

Please feel free to call me at (904) 739-2007 if you have any questions or require additional information.

Very truly yours,

ENVIRONMENTAL SCIENCE AND ENGINEERING, INC.

Lloyd H. Stebbins, P.E.
Manager
Industrial Environmental Department
Jacksonville Regional Office

LHS/cdb

Enclosures

54

F

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SENDER'S FEDERAL EXPRESS ACCOUNT NUMBER: 1014-2765-4

DATE: 10-30-87

52088

1 From (Your Name): Victor E. Garrison, P.E.

Your Phone Number (Very Important): (605)464-5600

Company: FT PIERCE UTILITIES AUTHORITY

Department/Floor No

Street Address: 206 S 6TH ST

City: FT PIERCE State: FL

AIRBILL NO. 055456240

ZIP® Zip Code Required For Correct Invoicing: 33454

2 To (Recipient's Name): Clair H. Fancy, P.E.

Recipient's Phone Number (Very Important): 904 488-8163

Company: Fla. Dept. Environ. Reg.ulation

Department/Floor No

Exact Street Address (Use of P.O. Boxes or P.O.® Zip Codes Will Delay Delivery And Result in Extra Charge.): 2600 Blair Stone Rd-Twin Towers Bldg

City: Tallahassee, State: FL

ZIP Street Address Zip Required (No P.O. Box® Zip Code): 32301

3 YOUR BILLING REFERENCE INFORMATION (FIRST 24 CHARACTERS WILL APPEAR ON INVOICE.)

PAYMENT [X] Bill Shipper [ ] Bill Recipient's FedEx Acct. No. Fill in line below [ ] Bill 3rd Party FedEx Acct. No. Fill in line below [ ] Bill Credit Card Fill in line below [ ] Cash

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H HOLD FOR PICK-UP AT THIS FEDERAL EXPRESS STATION: Street Address (See Service Guide or Call 800-238-5355)

City State

ZIP® Zip Code of Street Address Required

4 SERVICES CHECK ONLY ONE BOX

1 [ ] PRIORITY 1 Overnight Delivery Using Your Packaging

6 [ ] OVERNIGHT LETTER (Our Packaging) 9"x12"

OVERNIGHT DELIVERY USING OUR PACKAGING

2 [X] Courier-Pak Overnight Envelope 12"x 15½"

3 [ ] Overnight Box 12½"x 17½"x 3" A [ ]

4 [ ] Overnight Tube 38"x 6"x 6"x 6" B [ ]

5 [ ] STANDARD AIR Delivery not later than second business day

SERVICE COMMITMENT

PRIORITY 1 - Delivery is scheduled early next business morning in most locations. It may take two or more business days if the destination is outside our primary service areas.

STANDARD AIR - Delivery is generally next business day or not later than second business day. It may take three or more business days if the destination is outside our primary service areas.

DELIVERY AND SPECIAL HANDLING CHECK SERVICES REQUIRED

1 [ ] HOLD FOR PICK-UP Give the Federal Express address where you want package held in Section H at right.

2 [X] DELIVER WEEKDAY

3 [ ] DELIVER SATURDAY (Extra charge applies)

4 [ ] RESTRICTED ARTICLES SERVICE (P-1 and Standard Air Packages only. Extra charge applies.)

5 [ ] CONSTANT SURVEILLANCE SERVICE (CSS) (Extra charge applies)

6 [ ] DRY ICE ______ Lbs

7 [ ] OTHER SPECIAL SERVICE

8 [ ]

9 [ ] SATURDAY PICK-UP OR SATURDAY DROP-OFF (Extra charge applies)

PACKAGES	WEIGHT	YOUR DECLARED VALUE	OVER SIZE
1	2		
Total 1	Total 2	Total	

Received At: Shipper's Door, Regular Stop, On-Call Stop, [ ] Loc.

Fed. Ex. Corp. Employee No. 11394 R160

Date/Time For Federal Express Use: 10 30 87 1535

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

Federal Express Use

Base Charges

Declared Value Charge

Origin Agent Charge

Other

Total Charges

PART #2041738901 FEC-S-751-1000 REVISION DATE 2.85 PRINTED U.S.A. NCR

RECIPIENT'S COPY

Receipt 76191
$1000.00
AC 56-141460

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

DER

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301

NOV 2 1987

BAQM

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

APPLICATION TO ~~XXXXXXX~~/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combined Cycle Power Plant [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: Fort Pierce Utilities Authority COUNTY: St. Lucie

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) Gas Turbine/Waste Heat Boiler

SOURCE LOCATION: Street 311 North Indian River Drive City Fort Pierce

UTM: East 566.8 North 3,036.3

Latitude 27 ° 27 ' 00 "N Longitude 80 ° 19 ' 26 "W

APPLICANT NAME AND TITLE: Harry Schindehette, Director

APPLICANT ADDRESS: FPUA, P.O. Box 3191, Fort Pierce, Florida 33448

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Fort Pierce Utilities Authority

I certify that the statements made in this application for a 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

REFER TO ATTACHMENT 1

Signed: [signature]

Harry Schindehette, Director
Name and Title (Please Type)

Date: 10-30-87 Telephone No. (305)464-5600

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 judgment, that

[1] See Florida Administrative 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 ______________________

Lloyd H. Stebbins
Name (Please Type)

Environmental Science and Engineering, Inc.
Company Name (Please Type)

P.O. Box 4943, Jacksonville, Florida 32201
Mailing Address (Please Type)

Florida Registration No. 31838 Date: 10/29/87 Telephone No. (904)739-2007

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.

Refer to Attachment 2, Process Description, and Attachment 8, Process Flow Diagram

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction November 1, 1987 Completion of Construction December 1, 1988

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.)

Steam injection for reduction of NO_x emissions is an integral part of the gas turbine.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

N/A

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 40 ;

if power plant, hrs/yr 6720; if seasonal, describe: N/A

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? NO

   b. If yes, has "Lowest Achievable Emission Rate" been applied? NO

   c. If yes, list non-attainment pollutants. N/A

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. NO

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. NO

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? YES

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? N/a

   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.

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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		
Water	(N/A - NO	EMISSIONS	FROM WATER)	

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): 101,276 (Water)
2. Product Weight (lbs/hr): 87,000 (Steam)

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

REFER TO ATTACHMENT 4

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/yr	T/yr	
Particulates	4.0	13.44	N/A	N/A	26,880	13.44	A
SO_x	0.17	0.576	0.015%by vol **	275.8	1,853,376	926.69	A
NO_x	51.3	172.5	0.168%byvol **	110.9	745,248	372.62	A
VOC	3.6	12.1	N/A	N/A	24,192	12.1	A
CO	32.85	110.4	N/A	N/A	220,752	110.4	A

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated without control (See Section V, Item 3).

*Calculated. Refer to Attachment 4.

** Rule 17-2.660(2)(a), F.A.C. - Standards of Performance for New Stationary Sources

***Since there are no external control devices, the potential emissions will be the same as the allowable emissions for SO_x and NO_x. Since the rule does not prescribe allowable emissions for particulates, VOC and CO, the actual emissions have arbitrarily been used for this purpose.

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
NO_x emissions control by steam injection is an integral part of the gas turbine.				

E. Fuels REFER TO ATTACHMENT 5.

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	0.2858	0.396	396
No. 2 Distillate Fuel Oil (Emergency Back-Up)	2047	3000	415.3

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: Natural Gas

Percent Sulfur: 0.0288% Percent Ash: N/A

Density: 0.0468 lb/SCF XXXXXXX Typical Percent Nitrogen: 0.78%

Heat Capacity: 21,369 BTU/lb 1000 Btu/SCF XXXXXXX

Other Fuel Contaminants (which may cause air pollution): REFER TO ATTACHMENT 4

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average N/A Maximum N/A

G. Indicate liquid or solid wastes generated and method of disposal.

N/A

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 60 ft. Stack Diameter: 9'3" x 10' 7 1/8" * ft.

Gas Flow Rate: 353,500** ACFM 172,000** DSCFM Gas Exit Temperature: 450 °F.

Water Vapor Content: 10.06 % Velocity: 60 FPS

*Rectangular Stack **Calculated REFER TO ATTACHMENT 6

SECTION IV: INCINERATOR INFORMATION N/A

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Patholog-ical)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Inciner-ated							
Uncon-trolled (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 Type	Fuel BTU/hr	Temperature (°F)
Primary Chamber					
Secondary Chamber					

Stack Height: ____ ft. Stack Diamter: ____ 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 device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ____

Brief description of operating characteristics of control devices:

N/A

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

N/A

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)]
   REFER TO ATTACHMENT 3.
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.
   REFER TO ATTACHMENT 4.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   REFER TO ATTACHMENT 4.
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.)
   REFER TO ATTACHMENT 4.
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).
   REFER TO ATTACHMENT 4.
6. An 8 1/2" 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.
   REFER TO ATTACHMENT 7.
7. An 8 1/2" 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 (Example: Copy of relevant portion of USGS topographic map).
   REFER TO ATTACHMENT 8.
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   REFER TO ATTACHMENT 9.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation. 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. N/A

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY N/A

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[X] Yes [ ] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [ ] No

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration

D. Describe the existing control and treatment technology (if any).

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).

1.

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:

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 Costs:

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:

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 N/A

A. Company Monitored Data

1. ______no. sites ______ TSP ______( ) SO2* ______ 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

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

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

Pollutant	Emission Rate
TSP	____________________ grams/sec
SO^2	____________________ grams/sec

E. Emission Data Used in Modeling

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.

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.

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.

ATTACHMENT 1

SECTION I A

AUTHORIZATION

RESOLUTION NO. U.A. 81-2

A RESOLUTION AUTHORIZING THE DIRECTOR OF UTILITIES TO EXECUTE AND FILE CERTAIN PERMIT APPLICATION FORMS, AND EXECUTE AND FILE PETITIONS FOR FEDERAL ASSISTANCE AND/OR GRANTS; AND SETTING AN EFFECTIVE DATE.

WHEREAS, it is necessary from time to time for the Fort Pierce Utilities Authority of the City of Fort Pierce, Florida, to secure certain permits from certain agencies for certain construction, and file petitions for federal assistance and/or grants; and

WHEREAS, the permit application forms require the signature of an official authorized by law to act for said Authority;

NOW, THEREFORE, BE IT RESOLVED BY THE FORT PIERCE UTILITIES AUTHORITY OF THE CITY OF FORT PIERCE, FLORIDA:

SECTION 1. That the Director of the Fort Pierce Utilities Authority be, and is hereby directed to execute and file on behalf of the Fort Pierce Utilities Authority, all forms necessary for permission to construct, operate and maintain various facilities when said work pertains to any of the following agencies:

(a) The State Department of Transportation of the State of Florida

(b) The State Board of Health of the State of Florida

(c) The Central and Southern Florida Flood Control District of the State of Florida.

(d) The Florida East Coast Railway Company

(e) The Corps of Engineers, U. S. Department of the Army

(f) Florida Department of Environmental Regulation

(g) Environmental Protection Agency

(h) Department of Urban Development

SECTION 2. The Director of Utilities be, and is hereby directed, to execute and file petitions for federal assistance and/or grant applications for the study, planning, designing and construction, and other affidavits associated with such filings, of various facilities of the Fort Pierce Utilities Authority of the City of Fort Pierce, Florida.

SECTION 3. That the within resolution shall supercede Resolution U. A. 72-5 and shall become effective as of January 1, 1981.

PASSED AND ADOPTED this 3rd day of February, 1981.

ATTEST:

Secretary

Chairman

ATTACHMENT 2

PROCESS DESCRIPTION

COMBINED CYCLE UNIT

FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA

The new facility will consist of a combustion turbine-generator, a heat recovery steam generator (HRSG), cooling tower, and a steam turbine-generator. This configuration (Attachment 8-Process Flow Diagram) is commonly called a combined cycle facility because two separate energy producing cycles are combined to achieve greater overall efficiency.

Electrical energy will be produced directly from the combustion turbine-generator (23.4 MW). A significant portion of the waste heat from the products of combustion will be captured by passing the hot gas stream through a heat recovery steam generator (boiler). The steam produced will drive a smaller (8.2 MW) condensing turbine-generator.

Power produced by the facility will be transferred to the Authority's transmission system via step-up transformers and the existing 69kV substation at the powerplant.

The combined cycle unit will provide baseload power to the Fort Pierce community and the regional grid.

The new unit will use natural gas as the primary fuel and No. 2 fuel oil as an emergency secondary fuel.

Emissions control will be provided by steam injection into the turbine, which will reduce NO_x emissions by 65%.

23.4
8.2
31.6

ATTACHMENT 3
SECTION III.B., PROCESS RATE

FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA

Calculate total process input rate and product weight.

III.B.1. Total Process Input Rate (lbs/hr)

The only raw material in this process is the feedwater to the heat recovery steam generator (HRSG).

Consider a mass balance around the boiler:

Total Process Input Rate =
Product Steam + NO_x Control Steam + Blowdown

Evaluating the right side of the equation,

Product Steam = 87,000 lbs/hr [vendor guarantee]

NO_x Control Steam = 12,250 lbs/hr [vendor guarantee]

Assuming that blowdown is 2% of the HRSG feedwater flow (Total Process Input Rate),

Blowdown = 0.02 (Total Process Input Rate)
= 0.02 (87,000 + 12,250 + Blowdown)
= 0.02 (99,250 + Blowdown)
= 1985 + 0.02 (Blowdown)
= 2,026 lbs/hr

Therefore,

Total Process Input Rate = 87,000 + 12,250 + 2026 = **101,276 lbs/hr**

III.B.2. Product Weight (lbs/hr)

The only product measurable by weight is net steam to service.

Total Product Weight = **87,000** lbs/hr steam [vendor guarantee]

ATTACHMENT 4

SECTION III C

EMISSIONS CALCULATIONS
NO. 9 COMBINED CYCLE GAS TURBINE

Since no representative test data is available, the following emissions calculations are based on the "National Emissions Data System (NEDS) Source Classification Codes (SCC) and Emission Factor Listing," EPA, October 1985.

Calculated Emissions (Tons/Year) =

$$\frac{\text{Annual Operating Rate for SCC} \times \text{Emission Factor from SCC File} \times \text{Fuel Parameter if applicable}}{(2{,}000 \text{ lb/ton})} \times \frac{100\text{-Control Eff}}{100}$$

where:

Annual Operating Rate = Millions of Cubic Feet of Natural Gas Burned/Year

Emission Factor = Pounds of Pollutant/Million Cubic Feet of Gas Burned

Fuel Parameter = Ash or Sulfur Content of Fuel on a Weight Percent (%) Basis [Not Applicable for Combustion of Natural Gas]

Control Efficiency = Pollution Control Device Percent (%) Efficiency [Since No External Control Devices Are Included, This Factor Only Applies To NO_x]

EMISSIONS

A. ANNUAL OPERATING RATE

Using 40 wks/yr baseloading, the total annual operating time becomes,

24 hr/day x 7 days/wk x 40 wks/yr = 6720 hrs/yr

From Attachment 5,

Fuel Consumption Rate = 0.2858×10^6 CF/hr

Consequently, the Annual Operating Rate is,

$$6720 \text{ hrs/yr} \times 0.2858 \times 10^6 \text{ CF/hr} = 1920.58 \times 10^6 \text{ CF/yr}$$
$$= 1920.58 \text{ Million Cubic Feet Burned/Yr}$$

B. EMISSION FACTORS

From NEDS SCC 2-01-002-01 [Internal Combustion Engines - Electric Generation - 4911]

Natural Gas Emissions,

Pounds Of Pollutant Emitted Per Million CF Burned

Particulates	SO_x	NO_x	VOC	CO
14	0.6	413	12.6	115

C. FUEL PARAMETERS

Not applicable for natural gas.

D. CONTROL EFFICIENCY

Based on information from the turbine manufacturer (Refer to Attachment 7), Figure 17 on page 11 indicates the relationship of the ratio of NO_x with water/NO_x dry to the water/fuel mass ratio.

From Attachment 3, Steaming Rate for NO_x Control = 12,250 lb/hr
From Attachment 5, Fuel Consumption Rate = 285,800 CF/hr

Since,

Density of Air = 0.0808 lb/CF (from Perry's Chemical Engineers Handbook, 4th Ed., 1963)
Specific Gravity of Natural Gas = 0.579 (from fuel specifications)

Then,

Fuel Consumption Rate (Weight Basis)
= 285,800 CF/hr x 0.0808 lb/CF x 0.579 = 13,371 lb/hr

Consequently, the steam/fuel ratio becomes,

12,250 lb/hr steam/13,371 lb/hr fuel = 0.916 steam/fuel mass ratio

However, the vendor also reports that:

For a given NO_x reduction, approximately 1.62 times as much steam as water on a mass basis is required for NO_x Control.

Therefore, the steam/fuel ratio can be converted to the water/fuel ratio as follows:

$$\frac{0.916}{1.62} = 0.565 \text{ lbs/hr water/lbs/hr fuel}$$

A water/fuel mass ratio of 0.565 is equivalent to a NO_x with water/NO_x dry ratio of 0.435 (Attachment 7 - Page 11, Figure 17). Consequently, equivalent NO_x reduction efficiency is,

$$(1.00 - 0.435) \times 100 = 56.5\%$$

The control efficiency factor then becomes,

$$\frac{100 - 56.5}{100} = 0.435$$

EMISSIONS CALCULATIONS

The total annual emissions of each pollutant can readily be determined by finding the product of the values in paragraphs A, B, C, and D divided by the conversion factor, 2000 lbs/ton.

PARAMETER	A	x	B	x	C	x	D	=	ANNUAL EMISSIONS (T/Y)
Particulate	$\frac{1920.58}{2000}$		14						= 13.44
SO_x	$\frac{1920.58}{2000}$		0.6						= 0.576
NO_x	$\frac{1920.58}{2000}$		413				x 0.435		= 172.52
VOC	$\frac{1920.58}{2000}$		12.6						= 12.10
CO	$\frac{1920.58}{2000}$		115						= 110.4

ALLOWABLE EMISSIONS

According to the New Source Performance Standards (NSPS), 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines:

Standard for SO_2 = 0.015 percent by volume of stack gases at 15% oxygen on a dry basis, 40 CFR 60.333(a).

Standard for NO_x = [0.0150 (14.4/Y)] + F

where STD = Allowable NO_x emissions (percent by volume at 15% oxygen and on a dry basis.

Y = mfr's rated peak load (kilojoules per watthour, not to exceed 14.4 kilojoules per hour.

F = NO_x emission allowance for fuel-bound nitrogen.

ALLOWABLE SULFUR DIOXIDE EMISSION LIMIT

From Attachment 6, the dry stack gas flow rate at standard conditions is 10.32 x 10^6 DSCFH.

Applying the regulatory emission limit allows calculation of the volumetric flow of SO_2,

0.00015 x (10.32 x 10^6 DSCFH @ 32°F) = 1548 DSCFH SO_2

Converting to a lb mol/hr emission rate,

1548 DSCFH/(359 CF/lb mol) = 4.31 lb mol/hr

Since the mol density of SO_2 is,

SO_2 = 64 lb/lb mol

Then,

4.31 x 64 = 275.8 lb/hr SO_2

The total allowable annual emissions become,

275.8 lb/hr x 6720 hr/yr/2000 lb/ton = 926.69 T/Y SO_2

ALLOWABLE NITROGEN OXIDES EMISSION LIMIT

Use the above formula to determine the NO_x emission limit. Since "Y" is expressed in kilojoules per watt hour, the heat input rate must first be converted to kilojoules per hour.

Heat Input Rate of Gas Turbine = 285.8 x 10^6 Btu/hr.

Since There are 1054 joules in a Btu,

285.8 x 10^6 Btu/hr x 1.054 kilojoules/Btu = 301.2 x 10^6 kilojoules/hr.

The gross power output of the turbine generator is 23,410 KWH.

Therefore,

$$Y = \frac{301.2 \times 10^6 \text{ kilojoules/hr}}{23.4 \times 10^6 \text{ watt hr}} = 12.87 \text{ kilojoules/watt hr.}$$

Typically, natural gas has virtually no fuel-bound nitrogen.

Consequently,

$$F = 0$$

Therefore,

Allowable emissions =

$$STD = 0.0075 \times (14.4/12.87) = 0.00839\% \text{ by volume.}$$

Using the dry stack gas flow rate from Attachment 6, find the standard volumetric flow rate of NO_x.

$$0.0000839 \times (10.32 \times 10^6 \text{ DSCFH @ } 32°F) = 865.8 \text{ DSCFH } NO_x.$$

Converting to a lb mol/hr emission rate,

$$865.8 \text{ DSCFH/(359 CF/lb mol)} = 2.41 \text{ lb mol/hr } NO_x.$$

Since the mol density of NO_x is,

$$NO_x = 46 \text{ lb/lb mol as } NO_2.$$

Then,

$$2.41 \times 46 = 110.9 \text{ lb/hr } NO_x.$$

The total allowable annual emissions become,

$$110.9 \text{ lb/hr} \times 6720 \text{ hr/yr/2000 lb/ton} = 372.6 \text{ T/Y } NO_x \text{ as } NO_2.$$

POTENTIAL EMISSIONS

Since there are no external control devices, the potential emissions will be the same as the allowable emissions.

ATTACHMENT 5

SECTION III E

FUELS

NATURAL GAS

Fuel Consumption

Based on Specifications and Manufacturers Guarantees:

Base Load Conditions:

Gross Output = 23,410 KW

Heat Input Rate = 285.8×10^6 Btu/hr

From the Fuel Specification,

Heat content of the natural gas = 1000 Btu/CF

Therefore,

$$\frac{285.8 \times 10^6 \text{ Btu/hr}}{1{,}000 \text{ Btu/CF}} = 0.2858 \times 10^6 \text{ CFH at Base Load Conditions}$$

= **0.2858 MMCF/hr at Base Load**

Heat Input

Maximum design flow rate = 6,600 CFM

Consequently,

$$6{,}600 \text{ CFM} \times 1{,}000 \text{ Btu/CF} \times 60 \text{ min/hr} = 396 \times 10^6 \text{ Btu/hr Maximum}$$

= **396 MMBtu/hr Maximum**

Percent Sulfur

Based on specifications, the natural gas contains

0.1 gr H_2S/SCF Natural Gas

0.1 gr/SCF = 0.0000143 lb/SCF Natural Gas

Therefore,

$$\frac{0.0000143 \text{ lb } H_2S/\text{SCF Natural Gas}}{0.0468 \text{ lb Natural Gas/SCF Natural Gas}} = 0.000306 \text{ lb } H_2S/\text{lb Natural Gas}$$

$$= 0.0306\% \; H_2S$$

Since the relative weights of sulfur and hydrogen sulfide can be expressed as,

$$\frac{S}{H_2S} = \frac{32}{34}$$

Then the weight percent of sulfur in natural gas becomes,

$$0.0306\% \; H_2S \times \frac{32}{34} = \underline{\underline{\mathbf{0.0288\%S}}}$$

Density

Based on specifications, the molecular weight of natural gas is 16.8 lb/lb mol.

Therefore,

$$\text{Density} = \frac{16.8 \text{ lb/lb mol}}{359 \text{ SCF/lb mol}} = \underline{\underline{\mathbf{0.0468 \text{ lb Natural Gas/SCF Natural Gas}}}}$$

Heat Capacity

Based on specifications, the natural gas has 1,000 Btu/SCF.

Therefore,

at 1,000 Btu/SCF, and
at 16.8 lb/lb mol, and
359 SCF/lb mol

the heat capacity of natural gas =

$$\frac{359 \text{ SCF/lb mol} \times 1000 \text{ Btu/SCF}}{16.8 \text{ lb/lb mol}} = \underline{\underline{\mathbf{21,369 \text{ Btu/lb}}}}$$

NO. 2 FUEL OIL

Based on Specification and Manufacturers Guarantees:

Base Load Conditions:

Gross Output = 22,930 KW

Heat Input Rate = 283.4×10^6 Btu/hr

From the fuel specifications,

Heat content of the fuel oil = 138,441 Btu/gal

Therefore,

$$\frac{283.4 \times 10^6 \text{ Btu/hr}}{138{,}441 \text{ Btu/gal}} = \underline{\underline{\textbf{2,047 gal/hr at Base Load Conditions}}}$$

Maximum design flow rate = 50 gpm

Converting to a per hour basis,

50 gpm x 60 min/hr = 3,000 gph

Consequently,

3,000 gph x 138,441 Btu/gal = 415.3×10^6 Btu/hr Maximum

= **415.3 MMBtu/hr Maximum**

SECTION 01005

FUEL SPECIFICATION

PART 1 - NATURAL GAS AND NO. 2 FUEL OIL

1-01 GAS ANALYSIS BY FLORIDA GAS TRANSMISSION CO.:

GAS ANALYSIS ID NUMBER 86 0135   MEAS. DIST. 07

METER STATION NAME FLA HYDROCARBON - OUTLET   STATION NO. 47188

FIELD DATA TAKEN BY A. Kattawar   DATE TAKEN 02-24-86

PRESSURE	630	TEMPERATURE	0	SPEC GRAV	0.5790
BTU	1016	WATER	0.0000	H_2S	0.1 gr

DATA ANALYZED BY Michael P. Campo   DATE ANAL. 03-06-86

COMPONENT	MOLE %	B.T.U.	SPEC GRAV.
OXYGEN	0.0000	0.0000	0.0000
NITROGEN	0.7800	0.0000	0.0075
CARBON DIOXIDE	0.9240	0.0000	0.0140
METHANE	95.6260	951.0000	0.5298
ETHANE	2.4310	42.3500	0.0252
PROPANE	0.1990	4.9300	0.0030
I BUTANE	0.0170	0.5400	0.0003
N BUTANE	0.0130	0.4200	0.0003
I PENTANE	0.0030	0.1200	0.0001
N PENTANE	0.0020	0.0800	0.0000
HEXANE PLUS	0.0050	0.2600	0.0002
TOTALS	100.0000	999.7000	0.5804

BTU/CU FT AT 14.73 PSIA 60 DEG F CORRECTED FOR Z

CALCULATED	SATURATED 1002	DRY 1020	0.0000 LB/MMCF 1020
CALORIMETER	SATURATED 1005	DRY 1023	
SPECIFIC GRAVITY - AIR = 1.0000		CALC 0.5804	RANAREX 0.5800

COMPRESSIBILITY FACTOR - Z = 0.9979
SUPERCOMPRESSIBILITY FACTOR CALC AT 0.5800 SP GR 600 PSIG 90 DEG
BY TEST WITH BURNETT APPARATUS 1.0362
CALC AGA-NX-19 NO DILUENTS 1.0369
CALC AGA-NX-19 ADJUSTED FOR DILUENTS 1.0352

NOTES PHYSICAL CONSTANTS FROM AGA 3
GPM FROM NGPA PUB NO. 2145-84
HEXANE PLUS DERIVED FROM PHILLIPS REF STANDARD

REMARKS: Percent difference with respect to Burrnett Apparatus for calculated value using AGA-NX-19 formula and adjusted for diluents equals (- 0.097).

1-02 NO. 2 FUEL OIL:

CERTIFICATE OF ANALYSIS OIL TESTS

		Date/Time	Analyst
A.P.I. Gravity @ 60°F	34.9	04/04/86 - 1100	RK
Sulphur, % by weight	0.355	04/07/86 - 0900	RK
BTU/lb	19,551	04/04/86 - 1300	RK
BTU/gal	138,441	04/04/86 - 1325	RK

PART 2 - (Not Used)

PART 3 - (Not Used)

END

ATTACHMENT 6

SECTION III H

EMISSION STACK GEOMETRY AND FLOW CHARACTERISTICS

The stack geometry calculation is based on the following project design conditions:

Turbine exhaust temperature: 924°F

Steam generator exhaust temperature: **450°F**

Turbine exhaust flow: 897,260 lb/hr

Using a typical turbine exhaust gas composition provided by the vendor, the pound molecular weight can be determined,

	VOLUME PERCENT	x	MOLECULAR WEIGHT	=	MOLE FRACTION
CO_2	2.617		44		1.151
H_2O	**10.059**		18		1.811
O_2	14.207		32		4.546
N_2	72.252		28		20.231
Ar	0.864		40		0.346
SO_2	0.00045		64		0.000
SO_3	0.00003		80		0.000
	99.99948				28.08 lb/lb mol

Using the mol density, calculate the stack gas flow rate at standard and actual conditions.

$$\frac{897{,}260\ \text{lb/hr}}{28.08\ \text{lb/lb mol}} = 31{,}954\ \text{lb mol/hr}$$

At standard conditions (32°F and 14.7 psia), the volume of 1.0 lb mol of any ideal gas equals 359 cubic feet.[1] Since the gases in the exhaust stream are similar to an ideal gas at standard conditions, the flow rate can be approximated as follows:

$$31{,}954 \text{ lb mol/hr} \times 359 \text{ CF/lb mol} = 11.47 \times 10^6 \text{ SCF/hr @ } 32°\text{F}$$

Correcting the exhaust gas flow rate for moisture and reducing to a per minute basis,

$$11.47 \times 10^6 \times [1.0 - 0.100597] = 10.32 \times 10^6 \text{ DSCFH @ } 32°\text{F}$$

Then,

$$10.32 \times 10^6 \text{ DSCFH/60 min/hr} = \underline{\underline{\mathbf{172{,}000\ DSCFM}}}$$

At actual conditions,

$$31{,}954 \text{ lb mol/hr} \times 359 \text{ CF/lb mol} \times \frac{910°\text{ R}}{492°\text{ R}} = 21.21 \times 10^6 \text{ ACFH @ } 450°\text{F}$$

On a per minute basis, the actual exhaust gas flow rate becomes,

$$21.21 \times 10^6 \text{ ACFH/60} = \underline{\underline{\mathbf{353{,}500\ ACFM}}}$$

Determine the velocity of the exhaust gases.

Design Stack Area: $\underline{\underline{\mathbf{9'3" \times 10'\ 7\ 1/8"}}}$ (9.25 ft x 10.59 ft) = 97.96 ft^2

Since,

$$353{,}500 \text{ ACFM/60} = 5{,}892 \text{ ACFS}$$

Then,

$$\frac{5892 \text{ CFS}}{97.96 \text{ ft}^2} = \underline{\underline{\mathbf{60.15\ FPS}}}$$

[1] "Introduction to Chemical Engineering," Anderson and Wenzel, McGraw-Hill Book Company, 1961, pg 126.

ATTACHMENT 7

General Electric Gas Turbine Multiple-Combustion System

Edward J. Walsh
Manager-Combustion Development
Gas Turbine Engineering and
Manufacturing Department
Gas Turbine Division
Schenectady, New York

CONTENTS

A TABLE OF CONVERSION FACTORS IS INCLUDED AT THE END OF THIS PUBLICATION

INTRODUCTION

All gas turbine power plants require a mechanism for releasing chemical energy in fuel to do work on the turbine. This generally requires a combustion system for burning fuel gas or liquid petroleum hydrocarbons. The design of the combustor is governed by the overall objective of the power plant and the design base of the manufacturer. Initially, the basis for all General Electric gas turbine power plants, whether heavy-duty industrial and electrical applications or aircraft engines, was the multiple-combustor concept. Because of space and height requirements, aircraft combustors have evolved from can-annular systems to very short annular combustors used in modern jet-powered aircraft.

On the other hand, heavy-duty gas turbines have continued to use the multiple-combustor concept. This is due to a better fit with our industrial gas turbine requirements of packaged power units, ease of inspection

GENERAL ELECTRIC
USA

MS7001 B/C, C, E, EA
REVERSE-FLOW COMBUSTION SYSTEM

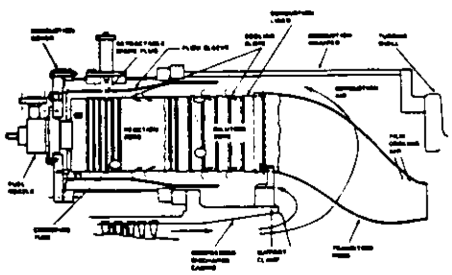

Figure 1

and maintenance, applicability for multiple fuels, and adaptability to low emission requirements. This provides the best opportunity for growth in future generations of gas turbines with increased firing temperatures and compressor pressure ratios.

As with most forms of energy conversion, the gas turbine affects the environment. The complex set of reactions that release the fuel energy also result in undesirable combustion emissions. The combustion system sustains, contains, and controls these reactions. The effects of gas turbine combustion exhaust emissions upon the environment is discussed in this paper, as well as the characteristics of these emissions, methods of measurement, and reduction techniques used to minimize adverse impact upon the environment. **The data presented are based upon specific tests; however, General Electric should be contacted for the values of emissions in a given application.**

COMBUSTION
LINER
COMPARISON

Figure 2

The commitment to continuous improvement of the reliability of the General Electric combustion systems is a very strong one. As the environmental requirements and fuels change, and as the machine ratings and efficiencies increase, General Electric is making changes in the combustion hardware to accommodate the aerodynamic and mechanical factors in order to maintain a reliable combustion system. This reliability not only includes the ability of the hardware to survive high temperature and vibration, but the combustor must ignite, crossfire and suppress smoke over a wide-operating range plus meet increasingly stringent environmental codes.

MULTIPLE-COMBUSTION SYSTEM

A typical reverse-flow multiple-combustion system, similar to those in most of the General Electric heavy-duty gas turbines, is shown in Figure 1. This system is a product of years of intensive development. In the combustor, a highly turbulent reaction occurs at temperatures above 3600 °F. The essential feature of the combustor is to stabilize the flame in a high velocity stream where sustained combustion is difficult. The combustion process must be stable over the wide range of fuel flows required for ignition, start-up, and full power. It must perform within desirable ranges of emissions, exit temperatures and fuel properties, and must minimize the parasitic pressure drop between compressor and turbine. General Electric's reverse-flow, multiple-combustion system adequately meets all these goals. The system is short, compact, lightweight and is mounted within the flange-to-flange machine on the same turbine base.

Only two basic combustion liner diameters are used for the entire heavy-duty product line. The number of liners is adjusted according to the machine airflow and pressure ratio. The liners for MS5001P, MS6001B, MS7001B, and MS7001E/MS9001E are shown in Figure 2. This standardization improves reliability and reduces the amount of development testing required.

The combustor ignition system uses spark plugs, crossfire tubes, and flame detectors. For reliability, two spark plugs and four (with Mark IV SPEEDTRONIC™) flame detectors are used. Ignition in one of the chambers produces a pressure rise which forces hot gases through the crossfire tubes, thereby propagating ignition to all other chambers within one second. Flame detectors, located diametrically opposite the spark plugs, signal the control system when the ignition process has been completed. Because of the relative simplicity and reliability of this technique, it is used in all General Electric-designed gas turbines.

Fuel is distributed into the combustion chambers by fuel nozzles. For gas, the fuel nozzle is a simple cap with accurately drilled metering holes. Liquid fuels are metered by a positive displacement gear element flow divider. Liquids are either pressure atomized or, if better smoke per-

SPEEDTRONIC™ Trademark of General Electric Company, U.S.A.

formance is required, air atomized. Residual fuel and crudes generally require atomizing air to achieve acceptable smoke performance.

The size of the combustion liners has been selected to provide the space required to completely burn residual fuel. Lighter fuels are easily burned in these liners. Smaller diameter combustors allow penetration of air jets into the combustor at acceptable pressure drops. This jet penetration is necessary to mix air with the fuel quickly to complete combustion without forming soot in fuel-rich pockets. The highly stirred flame produced by these jets also reduces radiation to the liner walls, benefiting liner life.

The combustion liners are made of a high-temperature material (Hastelloy-X) and carefully air cooled to tolerate high-temperature gases a few millimeters from the combustor liner wall. As firing temperatures have increased, more air is needed to combine with the fuel for adequate combustion and less air is available for liner wall cooling. This penalty has been offset by providing a more efficient cooling system and by reducing the surface area (length) of the liner. Louver cooling, which has been highly successful and reliable over the years, has been replaced by slot cooling in the turbines with the highest firing temperatures. The slot cooling method reduces liner material temperatures by 250 °F compared to an equivalent louver system.

The length of the combustor is selected to provide residence time to complete the combustion reaction for the variety of fuels burned in the turbine and to dilute the combustion products with excess air, forming a gas temperature profile acceptable to the turbine. The temperature profile of hot gases entering the turbine section is carefully developed to provide maximum life for the nozzles and buckets. The average radial profile from the combustors will produce lower temperatures near the bucket root where the centrifugal stress is maximum.

In the reverse-flow multiple-combustor arrangement, the transition piece (which channels the high-temperature gas from the combustion liner exit to the first-stage nozzle inlet) is cooled by air flowing from the compressor discharge. This provides effective convective cooling of the transition piece for firing temperatures up to 1850 °F. The radial outer wall of the transition piece near the first-stage nozzle is less effectively cooled, and at firing temperatures above 1850 °F, jet film cooling is added.

By virtue of its smaller size and weight, the multiple-combustor system has an inherent advantage over other systems in handling, shipping, erection, and material usage. Table 1 highlights some of the details of the General Electric multiple-combustion system.

Design Criteria

The combustion system is designed for a given application and machine series using analytical and experimental techniques. Much emphasis is placed upon tailoring the design to follow past practices and to take advantage of General Electric's many years of successful experience in the gas turbine field. Analytical techniques include sophisticated computer programs to determine airflow splits, heat transfer coefficients, flame temperature, flame radiation, estimated emissions, required equivalence ratios, structural loads, metal temperatures, operating stresses, and estimated dynamic pressure performance.

Once the general design of the combustor has been defined, conceptual layouts are made, analyzed, and modified. Hardware is procured, instrumented, and then tested in the Gas Turbine Development Laboratory. The gas turbine combustion system is evaluated on the basis of specific design parameters for which criteria are well established. Some of these parameters are listed in Table 2. After development testing, final detailed drawings are made.

Table 1

HIGHLIGHTS OF THE GEOMETRIC CONSTRUCTION OF THE GENERAL ELECTRIC MULTIPLE-COMBUSTION SYSTEM

	5001P	5002B	6001B	7001B	7001E	9001B	9001E
Number of Combustors	10	12	10	10	10	14	14
Liner Length/Diameter	40.5/10.7	44/10.7	29.0/10.7	56.6/14.3	38.6/14.3	56.6/14.3	38.6/14.3
Liner Weight	35	35	25	55	40	55	40
Transition Piece Length	34	26.5	19.7	36.2	36.7	43.3	23.75
Transition Piece Weight	47	36	61	100	120	84	65

NOTE: All dimensions in inches and weights in pounds

Table 2

COMBUSTION SYSTEM DESIGN PARAMETERS

• Ignition	• Efficiency
• Low-and High-Flow Blowout	• Combustor Exit Temperature Profile
• Crossfiring	• Pressure Drop -Stress Field
• Emissions - NO_x - CO - UHC - SO_x - Smoke - Particulates	• Metal Temperatures -Creep -Gradients • Dynamic Pressures -Wear -LCF -HCF • Hardware Life -Wear -Creep -HCF -LCF

Ability to Test at Full Scale

Neither mathematical nor geometric modeling has been satisfactory for combustion development because a scale model does not reproduce the chemical reactions, heat release rates, and aerodynamic mixing of the completed design. Aerodynamic mixing, achieved by jet penetration from the walls of the combustor, is more difficult in a larger diameter combustor. For this reason, good smoke performance, which depends strongly on aerodynamic mixing, cannot be predicted from scale model tests. A practical combustor can be developed only in full-scale tests.

The predominant role of laboratory testing in combustor development underscores the desirability of the multiple-combustor approach. Almost all of the development work can be done on a full-size single burner test stand at full machine operating conditions, with only a fraction of the fuel and air in a full gas turbine.

As a result, all General Electric heavy-duty gas turbines with their fully-developed combustion systems are shipped from the factory with the system fully tuned. This precludes the need for any start-up adjustments and minimizes the need for running tests in the field at the customer's site. The erection of the gas turbine is simple and quick.

Development Laboratory

The General Electric Gas Turbine Division Development Laboratory is a multimillion dollar facility dedicated to the advancement of heavy-duty gas turbines. A major portion of this facility is configured to handle the various combustion development programs. Although component test rigs are used for fuel-nozzle design and development and selective screening tests are conducted using small atmospheric-type burners, all of the combustion systems designed by the Division are tested using full-scale hardware at machine airflow, pressure, and temperature.

GAS TURBINE DEVELOPMENT LABORATORY

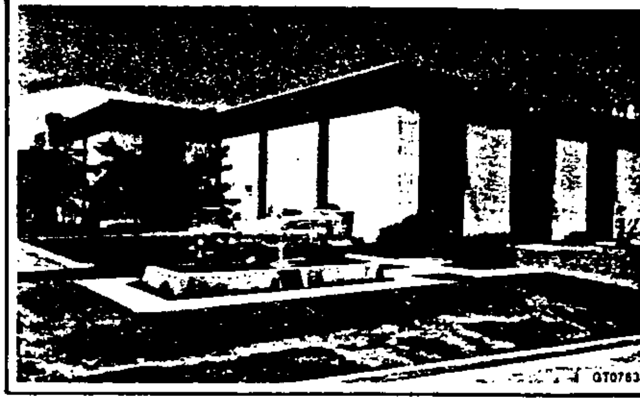

Figure 3

The Development Laboratory shown in Figure 3 has a process air supply capable of delivering over 60 lb/sec of air, which is equivalent to a single combustion chamber for the largest General Electric gas turbine. The single-burner test stand can be linked to a pie-shaped cut from the gas turbine combustion system surrounded by a pressure vessel. The test rig is configured aerodynamically to simulate the flow passages within the gas turbine. Figure 4 shows a typical single-burner combustor test stand located in the Gas Turbine Development Laboratory. Instrumentation is placed strategically in and around the test rig to measure inlet airflow and fuel flow rates, combustion inlet and discharge temperatures, pressure drops, metal temperatures, emissions, and dynamic pressures.

TYPICAL COMBUSTION SINGLE-BURNER TEST STAND

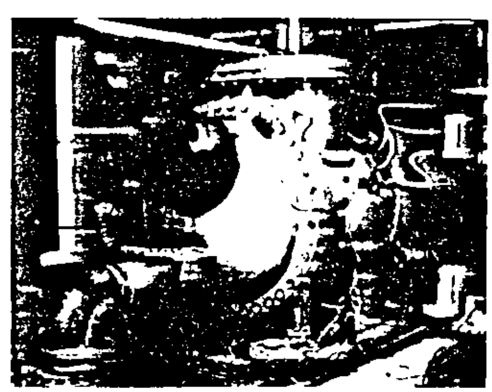

Figure 4

Table 3

GAS TURBINE EMISSIONS BURNING CONVENTIONAL FUELS

Major Species	Typical Concentration (vol %)	Source	Comments
Nitrogen (N_2)	66-72	Inlet Air	—
Oxygen (O_2)	12-18	Inlet	—
Carbon Dioxide (CO_2)	1-5	Oxidation of Fuel Carbon	Greenhouse Effect Potential Concern
Water Vapor (H_2O)	1-5	Oxidation of Fuel Hydrogen	—
Pollutants	**Typical Concentration (pmmv)**	**Source**	**Comments**
Nitric Oxide (NO)	20-220	Oxidation of Atmosphere Nitrogen	U.S. EPA NSPS California—Some areas 140 lbm/hr
Nitrogen Dioxide (NO_2)	2-20	Oxidation of Fuel-Bound Organic Nitrogen	Other Local Areas More Stringent than NSPS
Carbon Monoxide (CO)	5-330	Incomplete Oxidation of Fuel Carbon	
Sulfur Dioxide (SO_2)	Trace-100	Oxidation of Fuel-Bound Organic Sulfur	U.S. EPA NSPS—Fuel Limitation
Sulfur Trioxide (SO_3)	Trace-3		California—Some Areas Include SO_3 in Particulates as $H_2SO_4 \cdot N\,H_2O$
Unburned Hydrocarbons (UHC)	5-300	Incomplete Oxidation of Fuel or Intermediates	Local Areas Because of Nonattainment or No Significant Deterioration
Particulate Matter Smoke	Trace-25	Inlet Ingestion, Fuel Ash, Hot-Gas-Path Attrition, Incomplete Oxidation of Fuel or Intermediates	California—Some Areas 10 lbm/hr Including SO_3 as H_2SO_4 Other Local Areas More Stringent

The Development Laboratory has various fuel supplies including propane, methane, distillate, residual, and special liquid fuels. In addition, it is possible to blend combustible gases with nitrogen to simulate low-Btu coal-derived fuels from either an air-blown gasifier or air/oxygen-blown gasifier. Special process gases can also be simulated. Each combustion system design is tested using the Laboratory facilities to verify performance. Hardware is modified and retested to ensure that all design goals established in the conceptual design phase are met.

EMISSIONS CHARACTERISTICS OF CONVENTIONAL COMBUSTION SYSTEMS

Emissions from the stationary gas turbine are listed in Table 3. As shown, there are two distinct categories. The major species CO_2, N_2, H_2O, and O_2 are present in percent concentrations. The minor species, or pollutants, such as CO, UHC, NO_x, SO_x, and particulates are present in parts per million concentrations. In general, given the fuel composition and machine operating conditions, the major species emissions can be calculated. The minor species, with the exception of total sulfur oxides, cannot. Characterization of the pollutants requires careful measurement and semitheoretical analysis.

The pollutants in Table 3 are a function of gas turbine operating conditions and fuel composition. In the following sections, each pollutant will be considered as a function of operating conditions under the broad subdivisions of gaseous and liquid fuels.

Nitrogen Oxides

Nitrogen oxides ($NO_x = NO + NO_2$) must be divided into two classes according to their mechanism of formation. Nitrogen oxides formed from oxidation of the free nitrogen in the combustion air or fuel are called

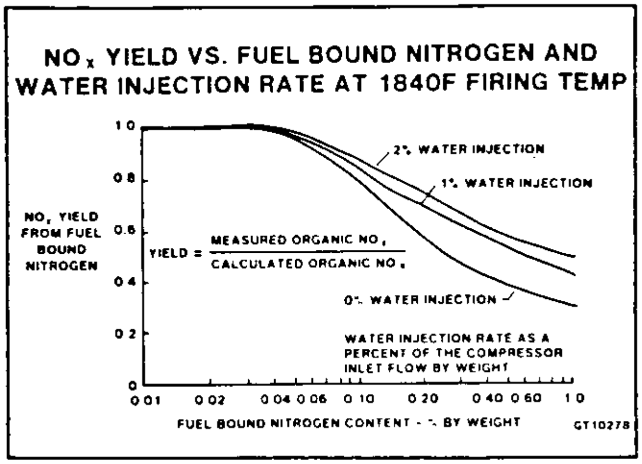

Figure 5

"thermal NO_x." They are mainly a function of the stoichiometric adiabatic flame temperature of the fuel which is the temperature reached by burning a theoretically correct mixture of fuel and air in an insulated vessel.

The following is the relationship between combustor operating conditions and thermal NO_x production:

- NO_x increases directly with fuel-to-air ratio
- NO_x increases exponentially with combustor inlet temperature
- NO_x increases with the square root of the combustor inlet pressure ratio
- NO_x decreases exponentially with increasing water or steam injection or increasing specific humidity

Emissions which are due to oxidation of organically bound nitrogen in the fuel (fuel-bound nitrogen) are called "organic NO_x". Only a few parts per million of the available free nitrogen are oxidized to form nitrogen oxide, but the oxidation of fuel-bound nitrogen (FBN) to NO_x is very efficient. As shown in Figure 5 for conventional combustion systems, the efficiency of conversion of FBN into nitrogen oxide is 100% at low FBN contents. At higher levels of FBN, the efficiency falls off to approximately 20% as shown.

Organic NO_x formation is less well understood than thermal NO_x formation. One important point is the reductions of flame temperatures to abate thermal NO_x have little positive, or even an adverse effect on organic NO_x. For liquid fuels, water and steam injection actually increases organic NO_x yields as shown in Figure 5.

Because of the lower hydrogen content of residual oils, the flame temperature for these fuels is, in general, lower that the flame temperature for No. 2 distillate. This property implies that they have the same or lower thermal NO_x production. Thus, the main feature of NO_x emissions for residual fuels containing significant FBN is the much greater contribution from organic NO_x and these fuels must be discussed on a case-by-case basis.

In general, gaseous fuels are classified according to their volumetric heating value. This value is useful in computing flowrates needed for a given heat input, sizing fuel nozzles and combustion chambers, and the like. However, the stoichiometric adiabatic flame temperature is a more important parameter for characterizing NO_x emission. Figure 6 shows relative thermal NO_x production plotted versus the stoichiometric adiabatic flame temperature of the fuel. The intermediate-Btu gases are of particular interest. Although their volumetric heating value is about 30% of that of natural gas, they produce one to four times as much NO_x. Data comparing No. 2 distillate and natural gas NO_x emission from a field test of an MS7001B confirm the importance of the flame temperature. The levels of emissions for natural gas are a very nearly constant fraction of those for No. 2 distilllate oil over the operating range of turbine inlet temperatures (see Figures 7, 8, and 9).

The low-Btu gases have, in general, flame temperatures below 3500 °F and correspondingly low thermal NO_x production. However, depending upon the fuel-gas clean-up train, these gases may contain significant quantities of ammonia. In a conventional combustion system, this contaminant is predicted to be converted, with a high efficiency, to NO_x. NO_x control measures such as water injection or steam injection which reduce flame temperature are predicted to have no effect on or to increase these organic NO_x emissions.

The NO_x performance of the MS7001E, MS6001B, and MS5001P gas turbines burning No.2 distillate and

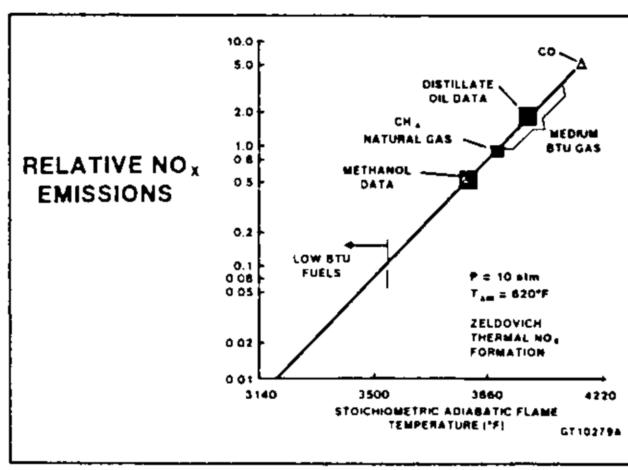

Figure 6

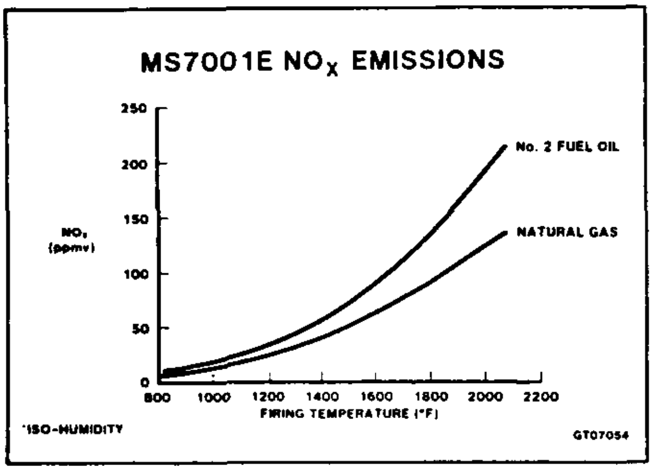

Figure 7

natural gas fuel is shown in Figures 7, 8, and 9 as a function of firing temperature (first-rotating stage-turbine inlet). For any given model of General Electric single-shaft constant-speed gas turbine, NO_X correlates very well with this one parameter. Exhaust oxygen concentration, which is a direct measure of heat release may also be used to characterize NO_X emissions.

Carbon Monoxide

Carbon monoxide emissions from a conventional General Electric gas turbine combustion system are less than 10 ppmv at all but very low loads for steady-state operation. During ignition and acceleration, there may be transient emission levels higher than those presented here. Because of the very short loading sequence of gas turbines, these levels make a negligible contribution to the integrated emissions. The emissions of carbon monoxide for the MS7001E are shown in Figure 10 plotted versus firing temperature. This characteristic curve is typical of all heavy-duty machine series.

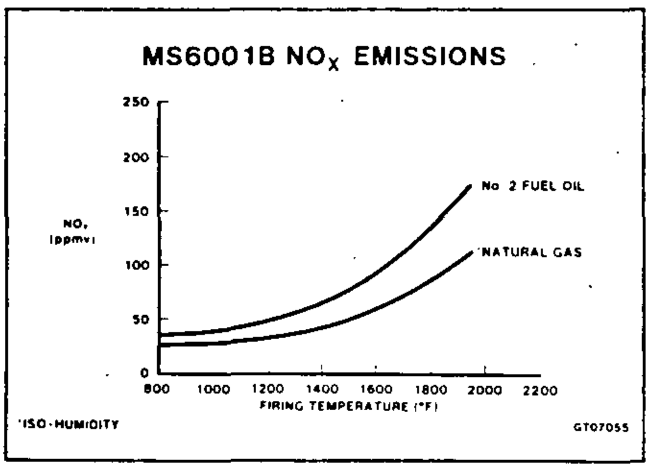

Figure 8

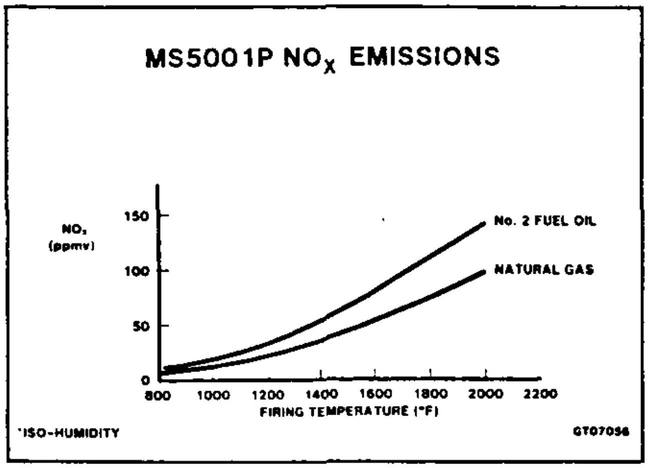

Figure 9

Unburned Hydrocarbons

Unburned hydrocarbons (UHC) like cabon monoxide, are associated with combustion inefficiency. When plotted versus firing temperature, the emissions from heavy-duty gas turbine combustors show the same type of hyperbolic curve (Figure 11). At all but very low loads, the UHC emission levels for No. 2 distillate and natural gas are less than 10 ppmv.

Sulfur Oxides

Sulfur oxides emissions from conventional General Electric gas turbines are a one-to-one function of the sulfur input in the fuel; that is, sulfur in the fuel equals $SO_2 + SO_3$ in the exhaust. Within the experimental error, a constant fraction (3.1% by weight) of the input sulfur is converted to SO_3 as shown in Figure 12. Depending upon the exhaust conditions, some or all of this SO_3 will be present as H_2SO_4. The combustor exit temperatures and pressures characteristic of modern gas turbines favor much higher

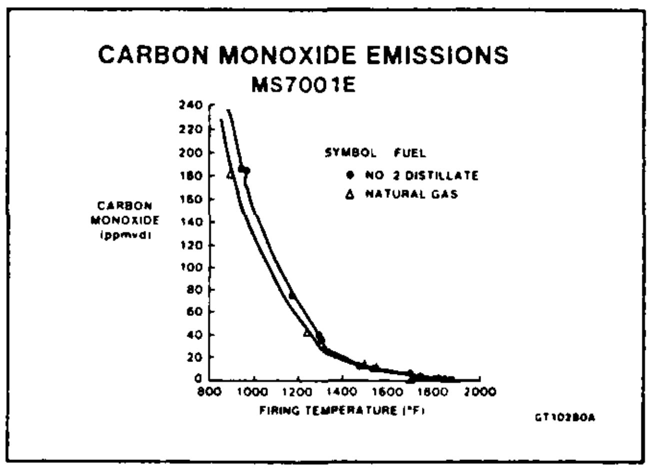

Figure 10

conversion efficiencies at equilibrium. Therefore, the low observed conversions are a result of diffusion flame burning and kinetic or mixing limitations.

Essentially, zero sulfur oxides are emitted when pipeline natural gas is burned in a gas turbine. Well-head gases, coal gases, process waste gases, and the like may contain significant quantities of sulfur generally in the form of H_2S. As in the case of No. 2 distillate this sulfur will be converted to sulfur oxides on a one-to-one basis. However, the fraction of this sulfur converted to SO_3 must be determined by test.

Particulates

Gas turbine exhaust particulate emission rates are influenced by the design of the combustion system, fuel properties, and combustor operating conditions. The principal components of the particulates are smoke, ash, ambient noncombustibles, and erosion and corrosion products. Two additional components that could be considered particulate matter in some localities are unburned hydrocarbons that are liquid at standard conditions and sulfuric acid mist (H_2SO_4).

Over a period of years General Electric has evaluated particulate emissions from GE Gas Turbines using a variety of sampling methods including the wet impinger method and USEPA Method Five. Several conclusions result from this experience.

- "Particulate matter" is a term defined only by the test method — there is no known analytical test that can demonstrate that the chemical compounds trapped in a filter, absorber, bubbler, or similar device actually existed in the gas turbine effluent. A particular example of this is SO_3 (which exists in the stack as a gas, but is trapped in a wet collection medium as H_2SO_4).

- Existing sampling methods, which were developed for sources such as residual oil or coal-fired boilers, paper mill recovery and bark boilers and the like, were not reliable when applied to gas turbines. In particular, stainless steel probes gave erratic test-to-test results even on the same gas turbine burning the same fuel.

- The errors due to sample loss in handling were comparable to the total sample catch for a gas turbine.

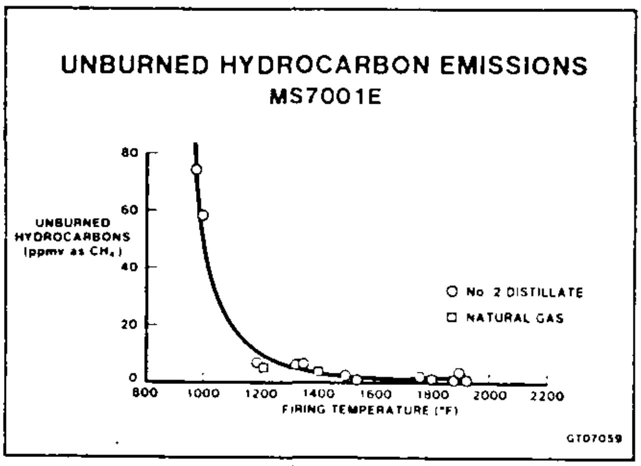

Figure 11

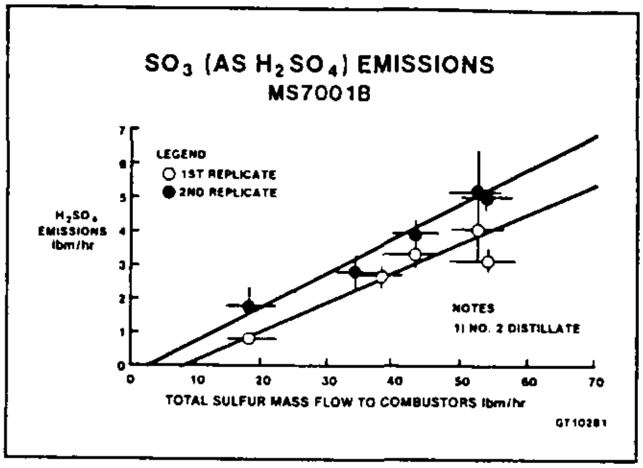

Figure 12

As a result of this experience, General Electric developed a sampling procedure intended to be specific to its products.

The results of using this method on an MS7001B burning No. 2 distillate are displayed in Figure 13. In some California localities, the H_2SO_4 emissions from Figure 12 must be added to the probe and filter catch to determine total particulate. Particulate emissions when burning natural gas fuel are below the detection and analysis limits of the method. Process off-gases, coal-derived gases, and the like may have detectable filterable particulate emissions if tars, noncombustible particulate, or other trace contaminants are found in the fuel gas. At present, there are insufficient data on actual operating systems to assess the magnitude of the problem.

Smoke

Smoke is the visible portion of filterable particulate material. The General Electric combustor design coupled with air atomization of liquid fuels has resulted in a nonvisible plume over the gas turbine load range for a wide variety of fuels. The General Electric Gas Turbine Division smoke measuring unit is the Von Brand Reflective Smoke Number (GEVBRSN). If this number is greater than 93 to 95 for the M7001E, then the plume will not be visible. For liquid fuels, the GEVBRSN is a function of the hydrogen content of the fuel (Figure 14). For natural gas fuel, the smoke number is essentially 99 to 100 over the load range.

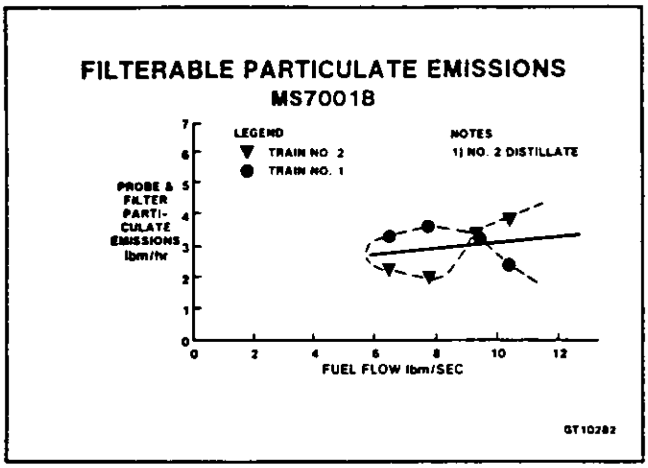

Figure 13

EMISSION REDUCTION TECHNIQUES

The gas turbine, in general, is a low emitter of exhaust pollutants because the fuel is burned with ample excess air to ensure complete combustion at all but the minimum load conditions or during start-up. However, regulations passed during the past 6 to 12 years have made it necessary to reduce the level of certain pollutants by more than a factor of three.

Most regulations today consider nitrogen oxides and sulfur dioxide to be the prime contributors to air pollution from stationary gas tubines. Some localities and states add particulates to the list of source emissions governed by the law, and it may be necessary to consider ground level concentration effects from carbon monoxide and unburned hydrocarbons (non-methane). Although nearly all regulation limits governing visible smoke emissions are much less stringent than those achievable from the gas turbine combustor, there are, nevertheless, isolated areas where extremely stringent standards exist.

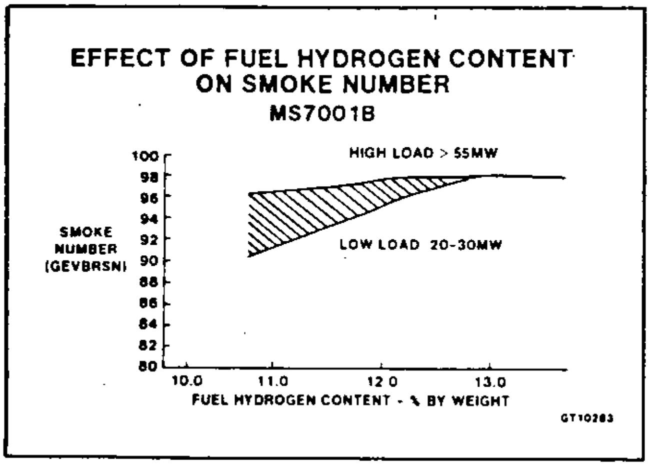

Figure 14

Because of the requirements dictated by environmental considerations, the General Electric Gas Turbine Division has developed techniques to reduce emissions to acceptable levels during the past 10 to 12 years. Emission control technologies can be divided into several categories, shown in Table 4.

Nitrogen Oxides Abatement

In order to reduce the oxides of nitrogen (NO_x) in the exhaust of the gas turbine, it is necessary to take into account the formation mechanism of NO_x in the combustor.

The earliest approach to reducing thermal NO_x from the gas turbine recognized the requirement for minimizing flame temperatures within the combustor. Examination of Figure 15 shows that the rate of NO_x formation can be significantly reduced by operating the reaction zone of a combustor at either very lean or very rich equivalence ratios. Prior to the advent of NO_x emission controls, gas turbine combustors were designed so that the reaction zone fuel/air ratio was near stoichiometric. A brief examination of Figure 15 shows that the rate of NO_x formation tends to a maximum at this condition, and that the rate can be significantly reduced by moving the reaction zone equivalence ratio toward either lean or rich operation.

Since the overall combustion system equivalence ratio must be lean (to limit turbine inlet temperature), it was natural that the first efforts to lower NO_x emissions were directed toward designing a combustor with a leaner reaction zone.

It quickly became apparent that the reduction in primary zone equivalence ratio at full operating conditions was lim-

Table 4

EMISSION CONTROL TECHNIQUES

NO_x	— Water or Steam Injection Selective Catalytic Reduction (SCR) Dry Low NO_x Catalytic Combustion
CO	— Combustor Design
UHC	— Combustor Design
SO_x	— Control Sulfur in Fuel
Particulates	— Fuel Composition
Smoke Reduction	• Combustor Design — Fuel Composition — Air Atomization
Particulate Reduction	• Fuel Composition — Sulfur — Ash

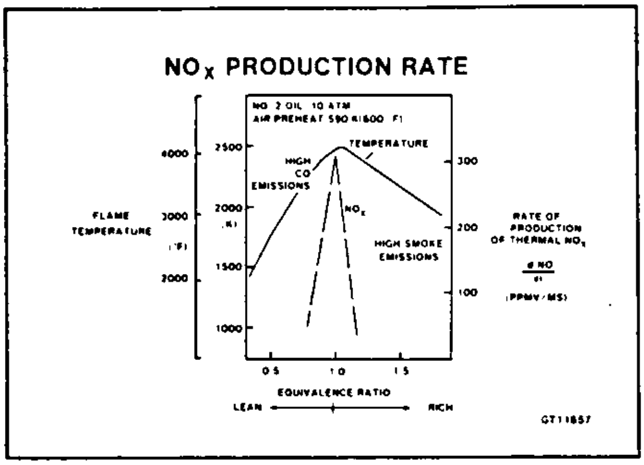

Figure 15

ited because of the large turndown in fuel flow (40 to 1), air flow (30 to 1), and fuel/air ratio (5 to 1) on industrial gas turbines. Further, the flame in a gas turbine is a diffusion flame since the fuel and air are injected directly into the reaction zone. Combustion occurs at or near stoichiometric conditions, and there is substantial recirculation within the reaction zone. The initial efforts to reduce NO_x by making the reaction zone of a conventional combustor lean gave about a 20% reduction in NO_x, but further efforts along this line did not prove fruitful.

Another approach to reducing NO_x formation is to reduce the flame temperature by introducing a heat sink into the flame zone. Water or steam are extremely effective at achieving this goal. Of course, a penalty in overall efficiency must be paid for the additional fuel required to heat the water to combustor temperature, although gas turbine output is enhanced because of the additional mass flow through the turbine. The water must, by necessity, be of boiler feedwater quality to prevent deposits and corrosion in the hot turbine gas path area downstream of the combustor. There are practical limits to the amount of water or steam that can be injected into the combustor before serious problems occur. This has been experimentally determined and must be taken into account in all applications if the combustor designer is to ensure long hardware life for the gas turbine user.

The General Electric Gas Turbine Division designed and developed a water injection system for NO_x control in the early 1970s. The system reduced the oxides of nitrogen to 225 ppmv at 3% O_2 on oil fuel and 125 ppmv at 3% O_2 on gas fuel to satisfy San Diego County Air Pollution Control District (SDAPCD) Rule 68. Although refinements such as staged H_2O flow and fuel/water monitoring equipment have been made to the system to satisfy the US Environmental Protection Agency New Source Performance Standards (NSPS), the basic system remains unchanged from its initial design. In fact, the SDAPCD regulation became the basic model for the NSPS.

Water injection is an extremely effective means for reducing NO_x formation; however, the combustor designer must observe certain cautions when using this reduction technique. To maximize the effectiveness of the water used, the fuel nozzle has been designed with additional passages to inject water into the combustor via the vortex generator in the combustor head end. The water is thus effectively mixed with the incoming combustion air and reaches the flame zone at its hottest point. Figure 16 shows schematically the General Electric heavy-duty H_2O injection system. The NO_x reduction achieved by water injection is plotted as a function of water-to-fuel ratio in Figure 17 for an MS7001E machine. The other machine series have similar NO_x abatement performance with water injection.

Two main factors can be observed with the use of H_2O injection for NO_x control:

- *Dynamic Pressure Activity within the Combustor.* Dynamic pressures can be defined as pressure oscillations within the combustor driven by the unsteady heat release rate inherent in any diffusion flame or by the weak coupling between heat release rate, turbulence, and acoustic modes. An example of the latter is selective amplification of combustion roar by the acoustic modes of the duct. Frequencies range from near zero to several hundred hertz.

  Figure 18 shows dynamic pressure activity for both water injection and steam injection. Water injection tends to excite the dynamic activity more than steam injection. Steam enters the combustor mixed with the air better than water does and thus has less impact on quenching the recirculating flame.

  The oscillating pressure loads on the combustion hardware act as vibratory forcing functions and therefore must be minimized to ensure long hardware

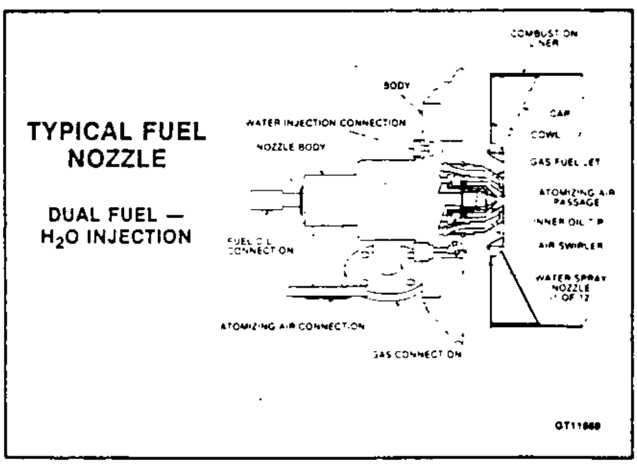

Figure 16

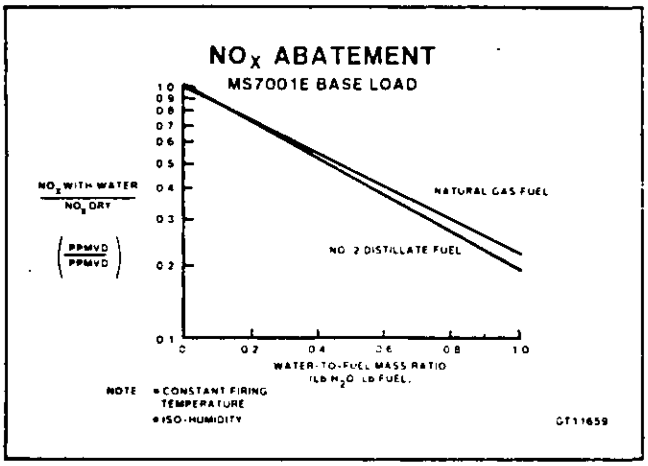

Figure 17

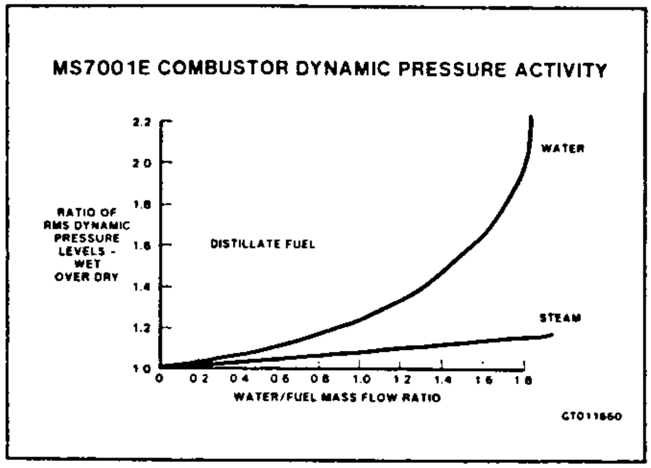

Figure 18

life. Water injection tends to increase (Figures 18 & 22) the dynamic pressure activity within the combustor.

Through combustor design modifications such as the addition of a multinozzle fuel system, significant reductions in dynamic pressure activity are possible — combustors have been designed that are capable of operating with no decrease in reliability while still complying with the most stringent codes to date.

- *Carbon Monoxide Emissions.* As more and more water is added to the combustor, a point is reached at which a sharp increase in carbon monoxide is observed. This point has been dubbed the "knee of the curve" and serves as a useful tool in defining maximum water injection levels for a given combustion system. Once the knee has been reached for any given turbine inlet temperature, one can expect to see a rapid increase in carbon monoxide emissions with the further addition of water. Obviously, the higher the turbine inlet temperature, the more tolerant the combustor is to the addition of water for NO_X control. Figure 19 shows the relationship of carbon monoxide emissions to water injection for a given combustion system for natural gas fuel.

A recent development to reduce NO_X is the use of head-end steam injection. Steam follows essentially the same path as water; however, experience in the laboratory has shown that the combustor dynamic pressures are much less sensitive to steam (Figure 18) than to water injection. This is due to the improved mixing characteristics of a gas (compared to liquid) when injected into the combustor. For a given NO_X reduction, approximately 1.62 times as much steam as water on a mass basis is required for control.

A system was designed and developed to inject steam into the reaction zone air via the end cover of the combustor (Figure 20) for three MS7001 machines placed into utility service in 1981. Extensive field meaurements have been made on one of these units burning both natural gas and distillate oil fuel with excellent results. As mentioned earlier, the dynamic pressure response is much lower when steam injection is used for NO_X abatement rather than water injection and this was confirmed in the field test program.

A similar combustion system was designed for an MS6001 machine used in a cogeneration industrial application. Test results are similar to the MS7001 machine. Identical steam injection configurations have been designed for gas-fired MS9001E machines used for electrical power generation. The NO_X performance has been thoroughly mapped out in the single burner test stand in the Development Laboratory with performance similar to the MS7001/6001 results.

Particulate and Smoke Reduction

Control techniques for particulate emissions with the exception of smoke are limited to control of the fuel composition.

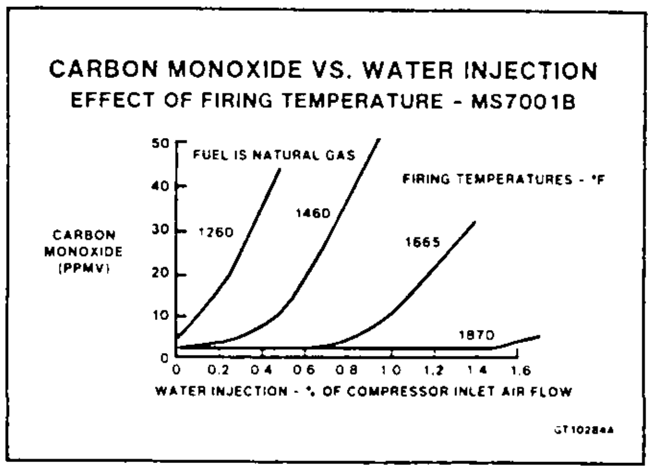

Figure 19

MS7001 STEAM INJECTION END COVER

Figure 20

Although smoke can be influenced by fuel composition, combustors can be designed which minimize emission of this pollutant. Heavy fuels such as crude oil and residual oil have low hydrogen levels and high carbon residue which increase smoking tendencies. General Electric has designed heavy-fuel combustors that have smoke performance comparable with those which burn distillate fuel.

Crude and residual fuel oil generally contain alkali metals (Na, K) in addition to vanadium and lead which cause hot corrosion of the turbine nozzles and buckets at the elevated firing temperatures of today's gas turbine. If the fuel is washed, oil-insoluble compounds containing the contaminants are removed. Filtration, centrifuging, or electrostatic precipitation is also effective in reducing the solid contaminants in the combustion products.

The contaminants that cannot be removed from the fuel can be controlled through the use of inhibitors. This process generally requires control and removal of added ash deposits from the turbine. The additional ash will contribute to the exhaust particulate emissions. Generally, the expected increase can be calculated from an analysis of the particular fuel being burned.

In some localities, condensible compounds such as SO_3 and condensible hydrocarbons are considered particulates. Sulfur trioxide, like SO_2, can best be minimized by controlling the amount of sulfur in the fuel. The major problem associated with sulfur compounds in the exhaust comes from the difficulty of measurement, as has been previously mentioned. Emissions of unburned hydrocarbons which are a liquid or solid at room temperature are very low and only make a minor contribution to the exhaust particulate loading.

HARDWARE TECHNOLOGY

The growth in compressor air flow and pressure ratio and the increased turbine output have required innovations in the combustion system mechanical design to provide for the higher turbine inlet temperature, while maintaining long life for the combustor parts. There has also been continuing development of combustion systems that will reduce the emission of nitrogen oxides and unburned hydrocarbons in order to meet the increasingly stringent environmental standards that are being applied throughout the world.

Slot-Cooled Liner

With the introduction of the MS7001 Model C turbine in 1974, the design of the combustion liner underwent a dramatic change. Borrowing General Electric Aircraft Engine combustion construction and cooling technology, the heavy-duty brazed ring construction, slot-cooled liner evolved. The construction details of the slot-cooled liner are depicted in the cutaway view shown in Figure 21. Note that the liner construction uses round holes (instead of sharp-ended louvers) which flood a continuous slot with air to provide a more efficient uniform cooling scheme. The advantage of slot cooling is to more efficiently cool the liner wall resulting in low metal temperatures. The slot-cooled liner developed in 1974 is basically the same liner that will be used in the uprated MS7001EA machine shipping in early 1985. Minor structural changes have been made around the combustion holes, spark plug/flame detector holes to improve resistance to cracking. Additional cooling has also been introduced to locally reduce metal temperatures around these large holes.

Over 1400 of these brazed-ring, slot-cooled liners have been installed into MS7001 machines over the past 10 years giving, on the whole, trouble free, reliable operation. Some liners have more than 40,000 hours of operation on them under all types of operating conditions and fuels. Some repairable cracking has occurred in the combustion zone of the liner and corrective action has been taken to eliminate this situation by improved mechanical reinforcement around the combustion holes and spark plug/flame detector holes. A liner reinforcing sleeve has been designed that will decrease operating stress at the edge of these large holes by a factor of two. Additional film cooling has also been added on the downstream side of these reinforced holes to minimize the possiblity of "hot streaks." Further reduction of bulk liner metal temperature and a smoothing out of thermal gradients is possible by the use of Thermal Barrier Coating (TBC).

The MS7001 slot-cooled liner is also used in the MS9001E machine — there being 14 combustion liners on the MS9001 versus 10 liners on the MS7001. A smaller diameter (Table 1) brazed-ring, slot-cooled liner has been standard on the MS6001 machine since introduction in 1978.

Quiet Combustor

The dynamic pressure oscillation activity within the combustor has increased with time as the gas turbine

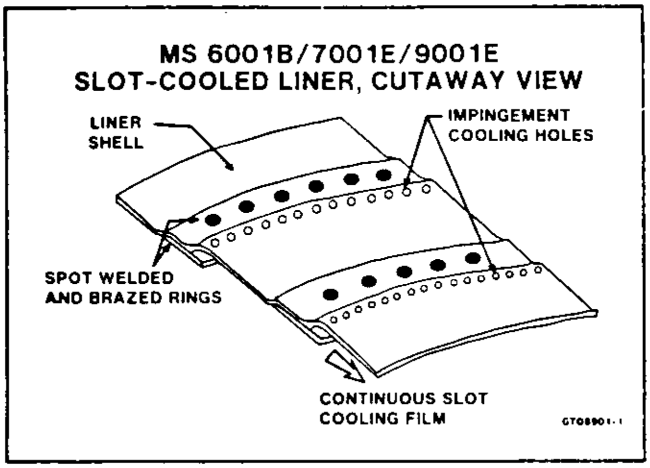

Figure 21

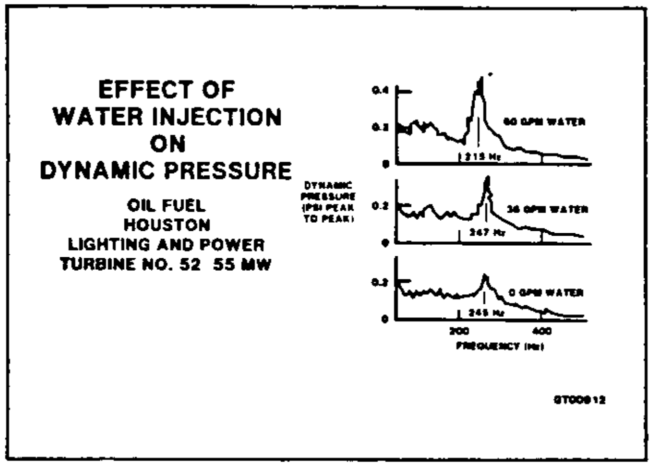

Figure 22

combustion system design has evolved. First with combustion design changes to reduce the visible smoke emissions, and then more recently to reduce the levels of nitrogen oxide emissions from the gas turbine exhaust. The injection of water (or steam) to reduce NO_x to even lower levels further increases the dynamic pressure oscillation as indicated in Figures 18 and 22. These changes, coupled with the increased combustor loading associated with higher firing temperatures, have led to increased maintenance.

A multiphase program was conducted in our Gas Turbine Development Laboratory from 1974 through 1980 with the goal of reducing the dynamic pressure activity in the combustor. Although many different concepts were built and tested, no design produced reduction in this dynamic activity comparable to that of a multi-fuel nozzle combustion system. Figure 23 shows an MS7001 multi-fuel nozzle cap arrangement for the combustion liner. The addition of water injection to this system design did not cause a significant increase in dynamic pressure activity. The benefits of this mutiple-fuel nozzle system are: low noise, low wear, decreased operating cost, increased availability, and combustor design that is retrofitable to the entire fleet of MS7001 machines.

A three-year program sponsored in part by Electric Power Research Institute (EPRI) was initiated in September 1980 to field endurance test a water-injected dual-fuel multi-nozzle quiet combustion system on an MS7001B combined cycle unit. The objective of this program was to improve the wear life of combustion liners, transition pieces, and seals, with the primary goal of increasing combustion inspection intervals.

The 12,268-hour (96 starts) endurance test began April 15, 1981 at the Houston Lighting and Power Company Wharton utility site and continued until November 27, 1983. In April 1982, a full set of combustor dynamic pressures were again recorded for comparison to the April 1981 data.

For all practical purposes the dynamic data from 1981 to 1982 were identical, indicating that the system remains quiet. The field endurance program demonstrated the major wear reduction benefits, and inspection/repair interval lengthening was achieved by the quiet multi-nozzle combustion system. Inspection intervals of 10,000 hours are clearly achievable for water injected machines, more than doubling prior experience with conventional systems.

Dry Low NO_x Combustor

As mentioned previously, the combustion system design must have the reduction of nitrogen oxide (NO_x) emission as a major objective in addition to the requirement of operating over the load range in a smokeless manner.

General Electric has developed a Dry Low NO_x combustion system that will meet the United States Environmental Protection Agency (EPA) NO_x requirements. The combustion system utilizes two stages of fuel injection and two

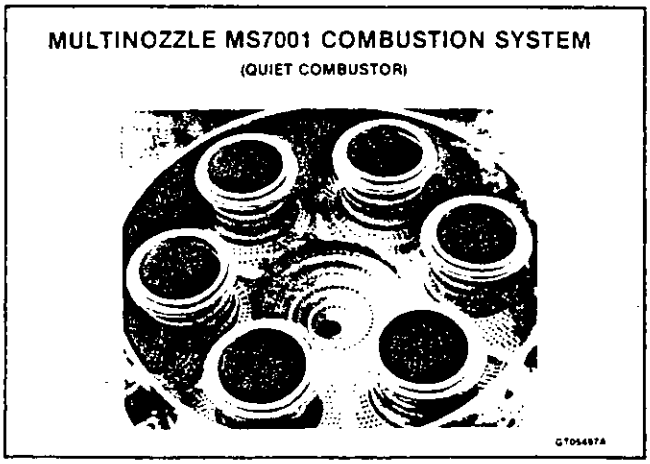

Figure 23

separate combustion zones. The combustor is shown in Figure 24 and utilizes a multi-nozzle primary stage and a single-nozzle secondary stage. No_x reduction is obtained, as with water or steam injection, by significantly lowering the peak flame temperature that occurs within the main reaction zone of the combustor. By using two stages of fuel injection, the combustor can be made to operate satisfactorily at fuel flows ranging from those at ignition conditions to those required for full load operation of the machine.

In 1980, field tests of the Dry Low NO_x combustion system were completed, utilizing an MS7001C gas turbine at the Houston Lighting and Power Company Wharton Station. These tests successfully demonstrated that the two-stage Dry Low No_x combustor was a practical arrangement and that the USEPA NO_x requirements can be met without the use of water or steam. Development is continuing on advanced versions of this system with the objective of achieving still lower dry NO_x levels.

Transition Piece Cylinder Mount

A new improved method of attaching the combustion transition piece aft bracket has been designed. The approach, using a cylinder-mount as shown in Figure 25 minimizes discontinuities between the colder bracket support and the hotter transition piece body. The cylinder mount bracket design significantly reduces the thermal stresses normally associated with a fin-type bracket common to most earlier transition piece designs.

The cylinder-mount concept has been tested extensively in the Gas Turbine Development Laboratory and on selected MS7001 field units. It is standard on all new production MS7001E machines being shipped in 1984. It is currently standard on all new production MS6001B and MS9001E units. Our plan for the MS5001 calls for the cylinder-mount transition piece to be introduced in limited quantities in late 1983 for field evaluation with full production by late 1984. The cylinder-mount attachment will improve the MS5001 transition piece cyclic life at the body attachment point such that the transition piece should withstand 10,000 thermal cycles at today's MS5001 turbine inlet temperature.

Thermal Barrier Coating

Over the years, the louvered liner has proven to be very reliable at moderate firing temperatures. Heat is radiated from the flame to the combustor walls which are cooled by air flow over the outside of the combustor, and by the thin film of air which is formed on the inside of the combustor wall by cooling louvers. Wear and thermal fatigue cracking of the louvers have occurred and require repair at normal inspection intervals.

A recent redesign of the MS5001 louvered liner consists of a new crossfire tube collar that incorporates splash plate cooling. A series of round holes around the collar impinge cooling air onto a splash plate on the inside of the liner which provides a cooling film to more efficiently cool the collar region and reduce the tendency for cracking.

Adapting from our Aircraft Engine Combustion Construction technology, a 10-12 mil ceramic thermal barrier coating (TBC) will be added to the inside surface of the liner wall. The best performing TBC coating has been a yttria-stabilized zirconia ceramic top coat over a NiCrAlY metal alloy bond coat. Use of shadowing techniques, which is commonly used on aircraft engine parts, keeps the TBC out of the cooling louvers as shown in Figure 26. Laboratory tests have shown that a temperature decrease of 27 °C to 116 °C (80 °F to 240 °F) is possible. Use of TBC on aircraft engine combustors has shown a smoothing of temperature gradients with a significant improvement in thermal fatigue life. Our plan calls for a number of sets of MS5001 TBC liners to be field endurance tested during 1983/84 with full production beginning late in 1984. For 1984 production turbines, TBC also been specified on MS7001 and MS9001 slot-cooled combustion liners used in high-firing temperature base load applications.

MS7001 DRY LOW NO_x COMBUSTOR

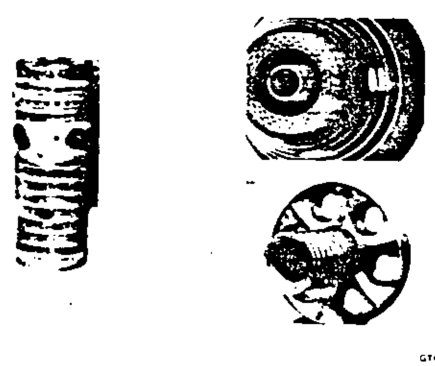

Figure 24

MS9001E TRANSITION PIECE WITH CYLINDER MOUNT AFT BRACKET

Figure 25

Transition Piece Improvement

A particular objective of all product improvement projects at General Electric is the enhancement of parts life and extension of service intervals. All 1984 MS7001E shipments have an improved transition piece design incorporated. This improvement is being brought about through material, design and cooling changes which have been the subject of a major development effort in 1982 and 1983. The changes have been exhaustively analyzed using three dimensional finite element computer codes and have been further evaluated in laboratory and field tests before reaching production units.

The transition piece is subject to gas flow hotter than any of the nozzles/buckets and temperature transients as rapid as fuel flow changes. At the same time, transition piece cooling is primarily accomplished by convective heat transfer to the low velocity compressor discharge air in the combustion wrapper. The transition piece is further subjected to any dynamic pressure oscillations from the combustion process which, as an energy addition device, is an inherent amplifier.

As a consequence of these conditions, transition pieces are subject to low cycle fatigue, high cycle fatigue, creep, wear and corrosion.

Early in the introduction of the MS7001 series turbine a combination of low cycle fatigue cracks and high cycle fatigue propagation led to premature transition piece failures. Both mechanical design alterations and aerodynamic changes were used to alleviate these problems. With extended life and additional firing temperature increases the problems of creep and wear became the dominant limiters of service life. It also became clear that more sophisticated analytical models were needed to support the design of this new hardware. Additionally, these analytical models have to be correlated and validated with field data since laboratory tests do not run long enough to develop satisfactory measures of service life.

MS5001 HIGH TECHNOLOGY THERMAL BARRIER COATED LOUVERED COMBUSTION LINER

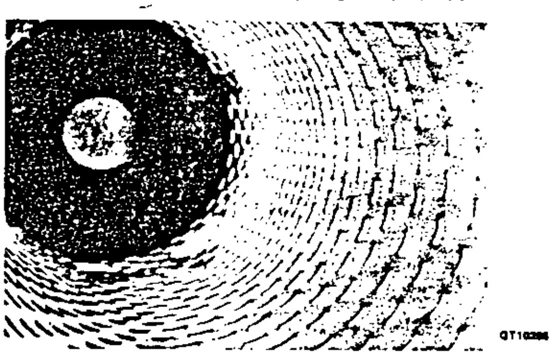

Figure 26

A major program was undertaken to generate new methodology and to develop a new transition piece design that would have extended inspection intervals and longer useful service life. A nine-point program was undertaken involving materials and process development, fluid flow analysis, performance and parts life analyses, heat transfer analyses, structural analyses, laboratory testing of designs and time dependent material behavior analyses and testing.

The materials effort involved conducting an ongoing program to evaluate more creep-resistant materials, other than the presently used Hastelloy-X, for combustion hardware applications; specifically, HS188, IN617, and Nimonic 263 (N263). These materials are very successfully used by aircraft gas turbine manufacturers for combustion hardware. The N263 was judged to be the superior transition piece material for both the current and future uprates of the MS7001 machine. The material showed a good balance of fatigue strength and creep resistance (Figure 27), significantly above Hastelloy-X and equal to or better than the more costly, less commercially available HS188. It also exhibits good fabrication qualities.

N263 is a nickel-base gamma-prime strengthened alloy with a nominal composition of 20% cobalt, 20% chromium, 6% molybdenium, 0.5% aluminum, and 2.2% titanium. The alloy can best be described as a weak nickel-base bucket alloy, primarily used in the wrought condition and was developed over 25 years ago for aircraft combustors. N263 is normally supplied in the solution heat-treated (2100 °F) condition, allowing for easy fabricability by both forming and welding operations, with a subsequent strengthening age cycle at 1475 °F for 8 hours. Although this particular cycle was recommended by the basic supplier and utilized by other gas tubine manufacturers, General Electric developed a more extensive heat treatment, following all fabrication and welding, dramatically improving the cross-weld properties, specifically stress rupture and fatigue strength. N263 material, using the General Electric processing sequence, has been successfully evaluated in field machines as both combustion liners and combustion transition pieces. All General Electric internally developed data on N263 plus our experience on manufacture and field endurance operation of N263 combustion hardware indicate it to be an excellent combustion alloy for transition pieces in higher turbine inlet temperature machines.

The new HTP784 transition piece design consists of the Block III positive curvature body shape (shown in Figure 28) made of N263 material. The picture frame will be a single piece, machined from N263 plate stock of modified Block III geometry and with improvements to reduce wear rates. An N263 external structural rib will be added to increase deflection resistance. The aft end mount will be

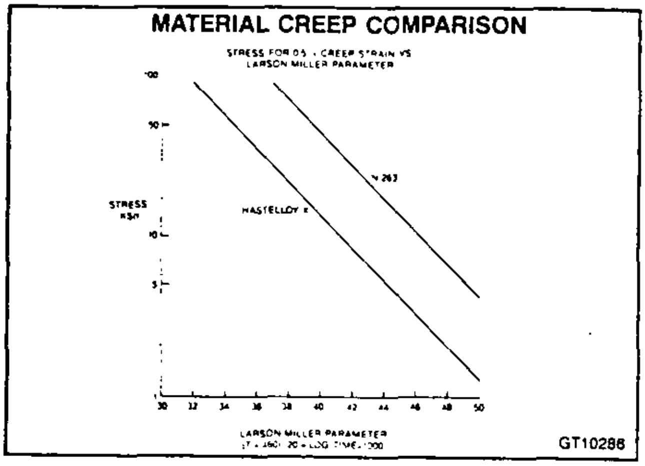

Figure 27

changed to a forged N263 cylinder mount insert welded into the body. The cylinder mount eliminates the discontinuity stresses at the body interface and improves LCF life, while the hinged aft bracket enhances torsional stability. The area under the aft bracket/cylinder is impingement cooled, with the cooling air discharging through the transition piece wall to provide jet film cooling aft of the cylinder mount insert.

The HPT784 transition piece aft end picture frame geometry has been changed to a slotted aft frame sealing system. Field experience has demonstrated that significant improvement in wear repair intervals can be had with the slotted design. The side seal had been changed to a thin, flat plate cobalt-base alloy with improved wear capability. The new side (or end) seals have small slots milled into the surface to provide air cooling for improved wear and seal life.

The aft portion of HPT784 transition piece (gas path side) is Thermal Barrier Coated (TBC) to decrease aft end

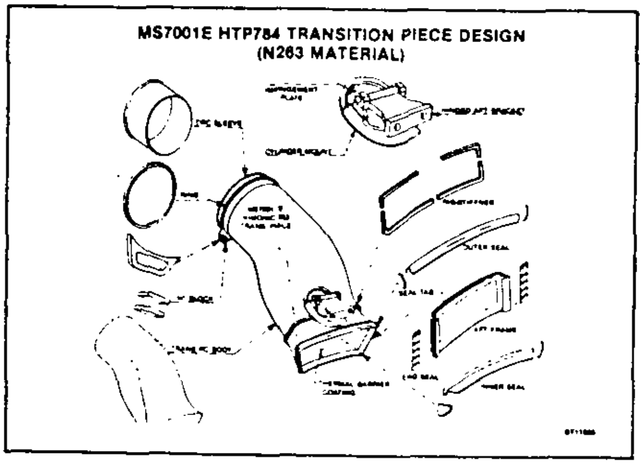

Figure 28

metal temperatures. In addition, the TBC will also smooth out thermal gradients to enhance cyclic capability. The new HPT784 transition piece has been designed to provide margin for future firing temperature uprates as well as to increase maintenance intervals and decrease repair costs.

A program is currently underway to introduce the HPT784 transition piece design concepts and material selections into the MS9001E machine. The new HTP985 transition piece for the MS9001E machine, based on current production commitments, will be available in late 1985.

Wear Resistant Materials

Combustion noise or dynamic pressure oscillations as previously discussed can cause relative motion between parts, especially at the sealing surfaces of the transition piece aft end. Wear of the transition piece picture frame is due to high frequency relative motion between the aft frame and the side seals and the inner floating seal. Oxidation debris coupled with the high frequency rubbing between two surfaces (seals and frame) causes the fretting wear that has been observed.

An effort is underway to develop a wear coating that could be applied to combustion components to improve wear resistance. The coating developed is a flame-sprayed hard surfacing that is applied to the transition piece aft frame wear surfaces. A cobalt-base alloy (Stellite) is flame sprayed on the aft frame to provide significant wear surface protection. To further enhance wear characteristics, the side (end) seals have been changed to a cast cobalt-base (Stellite) material. Laboratory wear tests and limited field experience have shown that cobalt-base alloys (Stellite) have a low rate of oxidation (and thus particulate formation) at high temperatures, thus reducing the rate of picture frame wear due to high cycle frame and seal mating surface rubbing. The cast cobalt-base end seal is sacrificial to the cobalt-base coated picture frame.

SUMMARY

General Electric has used multiple-combustion configurations on heavy-duty gas turbines since the first one was designed in the 1940s. We have used them in gas turbines that produce less than 10 MW to those greater than 100 MW. We know from experience with several thousand units that the concept works, and works well. We know what the configuration can do and we know how to apply it to the varied needs of our customers. These combustors have been used with a wide variety of fuels, firing temperatures, and emissions requirements and they have met their operating objectives.

The emission characteristics of the gas turbine have been presented, showing actual field test data. This type of baseline data is necessary if one is to design combustion systems to be environmentally acceptable in the marketplace. Obtaining field emission data is both expensive and time consuming. The Gas Turbine Division has invested in a mobile emission van, fully equipped to measure the various constituents in the exhaust gas such as NO_X, CO, UHC, SO_X, and particulates. This equipment has been employed by General Electric personnel to make numerous official emission compliance tests to satisfy both federal and state environmental agencies. Developing measurement techniques to ensure reliable, accurate data acquisition is an engineering science within itself.

Combustion hardware technology development is an ongoing activity and will continue to be so, especially in light of the environmental requirements and fuel flexibility requirement. Requirements created by leaner combustors and increased machine ratings have been dealt with, and inspection intervals have increased. Present and future design efforts continue in the area of combustor aerodynamics as well as in the mechanical design with a goal of providing the best we can while minimizing complexity, maintenance and cost.

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8) M.B. Hilt and J. Waslo, "Evaluation of NO_X Abatement Techniques through Combustion Design for Heavy-Duty Gas Turbines," ASME Paper 84-GT-48.

9) G.L. Touchton, "Influence of Gas Turbine Combustor Design and Operating Parameters on Effectiveness of NO_X Suppression by Injected Steam or Water," ASME Paper 84-JPGC-GT-3.

CONVERSION FACTORS

The following is a list of conversion factors most commonly used for gas turbine performance.

To Convert	To	Multiply By
acres	hectares	4.047×10^{-1}
atm	kg/cm^2	1.0333
atm	$lb/in.^2$	1.47×10^1
bars	atm	9.869×10^{-1}
bars	$lb/in.^2$	1.45×10^1
Btu	J (joules)	1.055×10^3
Btu	kcal	2.52×10^{-1}
Btu/h	kcal/h	2.520×10^{-1}
Btu/h	kJ/h	1.0548
Btu/h	W (watts)	2.931×10^{-1}
Btu/hp-h	kcal/kWh	3.379×10^{-1}
Btu/hp-h	kJ/kWh	1.4148
Btu/kWh	kcal/kWh	2.5198×10^{-1}
Btu/kWh	kJ/kWh	1.0548
Btu/lb	kcal/kg	5.555×10^{-1}
Btu/lb	kJ/kg	2.3256
°C	°F	(°C × 9/5) + 32
°C	K	°C + 273.18
cm^3	ft^3	3.531×10^{-5}
cm^3	$in.^3$	6.102×10^{-2}
°F	°C	(°F − 32) × 5/9
ft	m	3.048×10^{-1}
ft^2	m^2	9.29×10^{-2}
ft^3	l (liters)	2.832×10^1
ft^3	m^3	2.832×10^{-2}
ft-lb	Btu	1.286×10^{-3}
ft-lb	kg-m	1.383×10^{-1}
ft/min	km/h	1.8288×10^{-2}
ft^3/min	l/s	4.720×10^{-1}
ft^3/min	m^3/min	2.832×10^{-2}
gal	m^3	3.785×10^{-3}
gal/min	l/s	6.308×10^{-2}
hectares	acres	2.471
hp (U.S.)	kW	7.457×10^{-1}
hp (U.S.)	hp (metric)	1.014
in.	cm	2.540
in.	mm	2.54×10^1
$in.^2$	mm^2	6.452×10^2
in. of mercury	kg/cm^2	3.453×10^{-2}
in. of water (at 4 °C)	kg/cm^2	2.54×10^{-3}
in. of water (at 4 °C)	$lb/in.^2$	3.613×10^{-2}
J	Btu	9.486×10^{-4}
kg	lb	2.2046
kg/cm^2	$lb/in.^2$	1.422×10^1
kg-m	ft-lb	7.233
kg/m^3	lb/ft^3	6.243×10^{-2}
km	miles (statute)	6.214×10^{-1}
kW	hp	1.341
l	ft^3	3.531×10^{-2}
lb	kg	4.536×10^{-1}
$lb/in.^2$	kg/cm^2	7.03×10^{-2}
$lb/in.^2$	Pa	6.8948×10^3
$lb\text{-}ft^2$	$kg\text{-}m^2$	4.214×10^{-1}
l/min	ft^3/s	5.886×10^{-4}
l/min	gal/s	4.403×10^{-3}
m	ft	3.281
m^2	ft^2	1.076×10^1
m^3	ft^3	3.531×10^1
mile (statute)	km	1.6093
tons (metric)	kg	1.0×10^3
tons (metric)	lb	2.205×10^3
W	Btu/h	3.4129
W	Btu/min	5.688×10^{-2}
W	ft-lb/s	7.378×10^{-1}
W	hp	1.341×10^{-3}

1984 GAS TURBINE REFERENCE LIBRARY

GER-3400	STAG™ Combined-Cycle Operating Experience
GER-3401	STAG™ Combined-Cycle Product Line and Performance Characteristics
GER-3402	STAG™ Combined-Cycle Plant Engineering and Construction Management
GER-3403	Steam Turbines for STAG™ Combined-Cycle Power Systems
GER-3404	Heat Recovery Steam Generators for STAG™ Combined-Cycle Plants
GER-3405	Controls for STAG™ Combined-Cycle Plants
GER-3406	STAG™ Combined-Cycle Power Systems Reliability
GER-3407	STAG™ Combined-Cycle Power Systems Operation and Maintenance
GER-3408	STAG™ Combined-Cycle Fuel Flexibility and Economic Evaluation
GER-3409	STAG™ Combined-Cycle Plants in Power Generation Planning Analysis
GER-3410	Combined-Cycle Repowering Mechanics and Economics
GER-3411	STAG™ Combined-Cycle System Economics
GER-3412	Heavy-Duty Gas Turbine Maintenance Practices
GER-3413	GE MS6001—Heavy-Duty Gas Turbine
GER-3414	Gas Turbine Parts and Performance Technology
GER-3415	Gas Turbines in Mechanical Drive Applications
GER-3416	GE Compressor Product Line Review
GER-3418	Generators for Gas Turbine Applications
GER-3419	Gas Turbine Inlet Air Treatment
GER-3421	Advanced Materials and Coatings
GER-3422	GE MS7001 Heavy-Duty Gas Turbine
GER-3423	Electric Utility Gas Turbine Applications
GER-3424	Aircraft-Derivative Gas Turbine Maintenance Practices
GER-3425	GE LM5000 Aircraft-Derivative Gas Turbine System
GER-3426	GE SPEEDTRONIC™ Mark IV Control System
GER-3427	GE DATATRONIC™ Information and Control System
GER-3428	Fuels Flexibility in Heavy-Duty Gas Turbines
GER-3429	Meeting the Quality Commitment with Experience and Technology
GER-3430	Cogeneration Application Considerations
GER-3431	GE LM2500 Aircraft-Derivative Gas Turbine System
GER-3432	GE MS9000 Heavy-Duty Gas Turbine
GER-3433	Application of Gas Turbines in the Process Industry
GER-3434	Gas Turbine Design Philosophy
GER-3435	GE Gas Turbine Multiple-Combustion System
GER-3436	Project Management Concepts
GER-3437	GE Gas Turbine Product Line and Performance Characteristics
GER-3438	Gas Turbine Applications Utilizing Solid Fuels
GER-3439	Coal-Fired STAG™ Combined-Cycle Applications
GER-3451	Legislation and Regulations Affecting Cogeneration
GER-3452	Gas Turbine Support Systems
GER-3453	Gas Turbine Compressor Testing and System Analysis
GER-3454	Integrated Turbine-Compressor Systems
GER-3455	Process Application of an Integrated Steam Turbine Compressor System
GER-3456	Cogeneration Financial Incentives
GER-3457	Combined-Cycle Cogeneration Systems Design
GER-3458	Utility Impact on Cogeneration Project Feasibility
GER-3459	Cogeneration Project Implementation
GER-3460	Natural Circulation Heat Recovery Steam Generators
GER-3461	Geared Steam Turbine Generator Sets
GER-3462	Operating Characteristics of High-Pressure Centrifugal Compressors

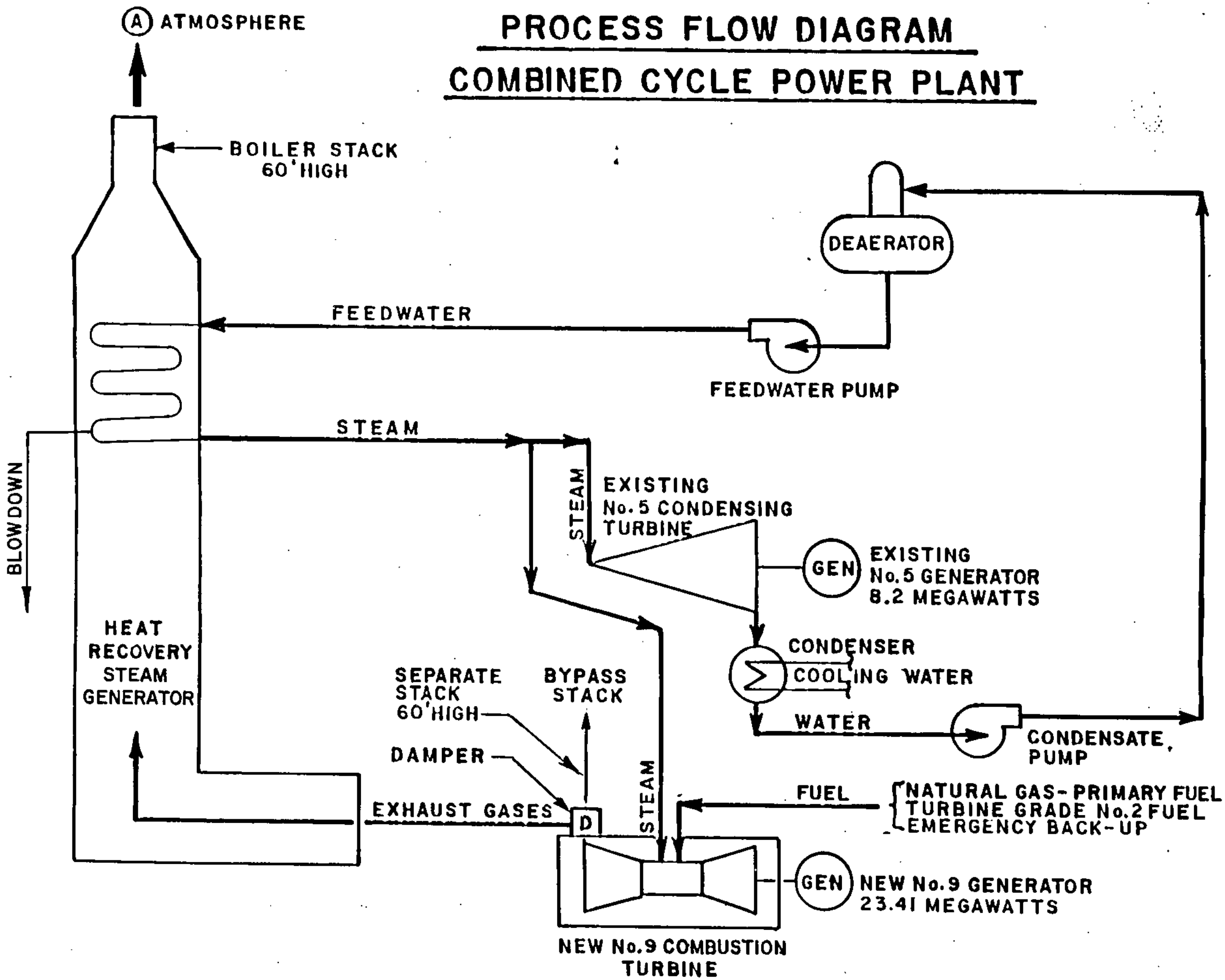
GAS TURBINE DIVISION
GENERAL ELECTRIC COMPANY
SCHENECTADY, NEW YORK 12345 USA

9 84 (3M)

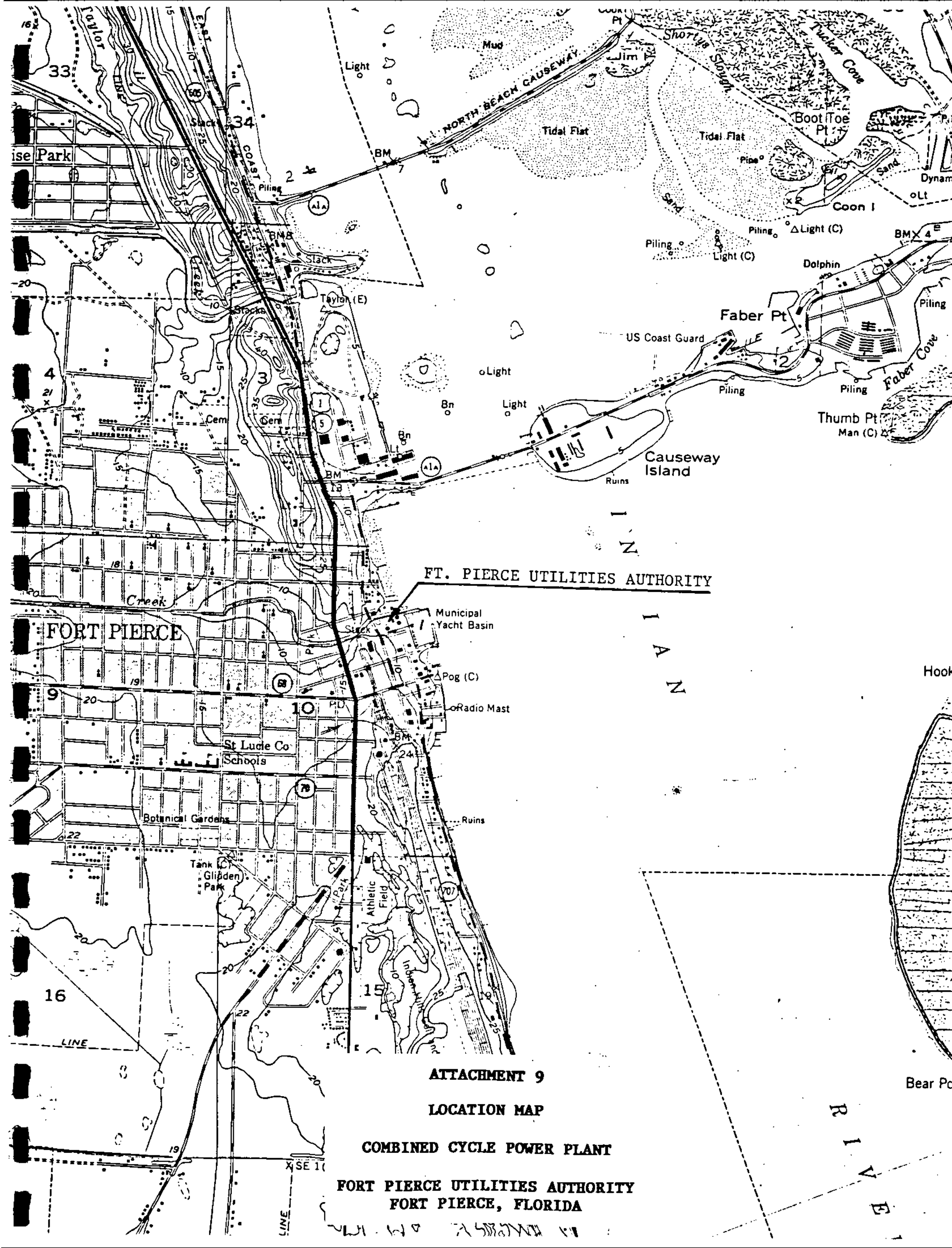
GENERAL ELECTRIC

PROCESS FLOW DIAGRAM

COMBINED CYCLE POWER PLANT



ATTACHMENT 8



ATTACHMENT 9

LOCATION MAP

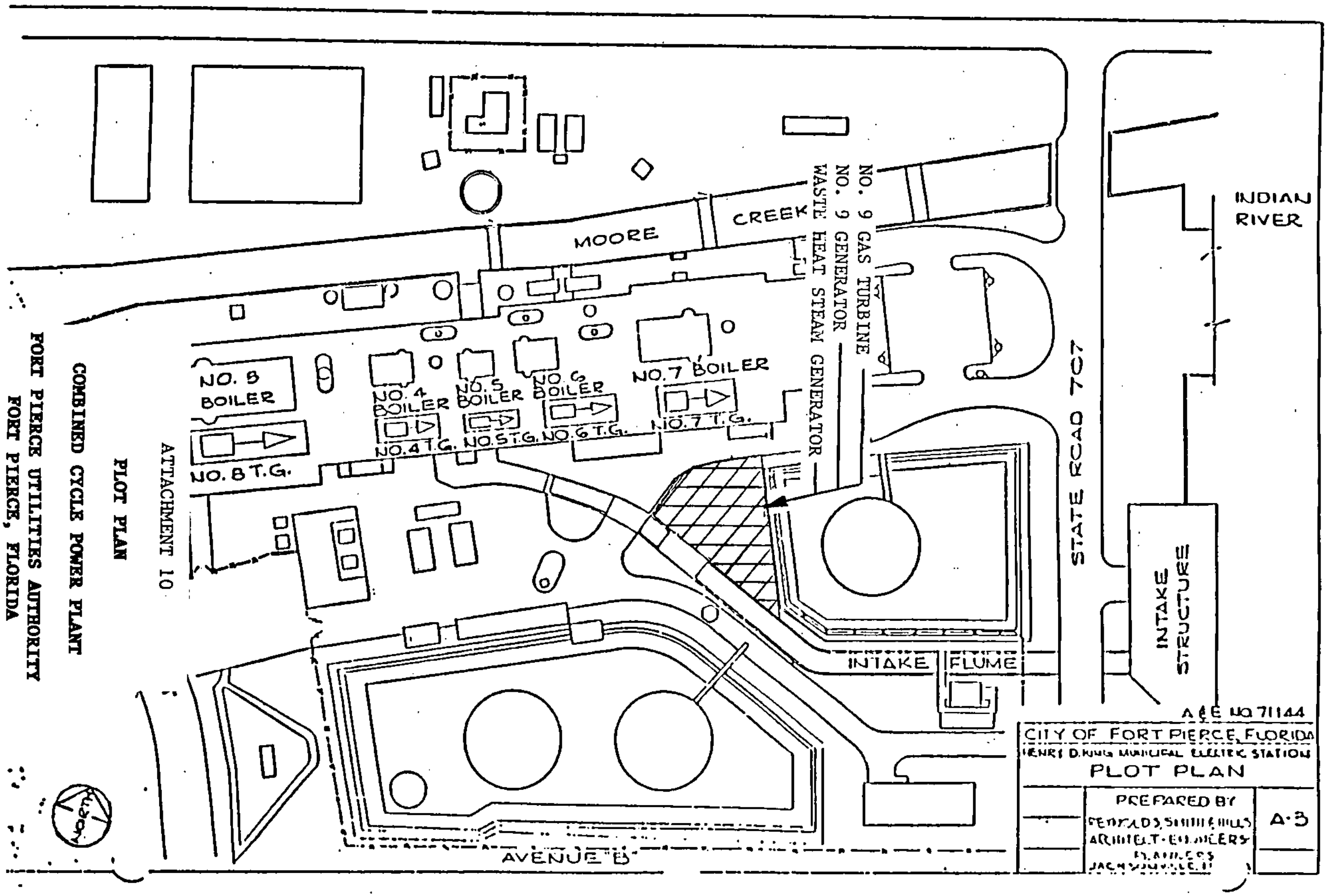
COMBINED CYCLE POWER PLANT

FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA

ATTACHMENT 10

PLOT PLAN

COMBINED CYCLE POWER PLANT
FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA



APPENDIX

FT. PIERCE UTILITIES AUTHORITY
CONTEMPORANEOUS EMISSIONS CALCULATIONS

The FPUA site is an attainment area for all criteria pollutants. Consequently, Chapter 17-2.500 FAC, "Prevention of Significant Deterioration" rules, require a New Source Review for any modification to a major facility which results in a significant net emissions increase, 17-2.500(2)(e)2. Refer to Table 500-2 FAC for singificant emission rate values. Accordingly, the NSR threshold for No. 9 Combined Cycle Gas Turbine has been evaluated by using the procedures for conducting a contemporaneous emissions calculation, 17-2.500(2)(e)3.

Since optimum opertion of Unit 9 will allow some curtailment of Units 7 and 8, the effective increase in plant efficiency can be used to limit emissions to just below the net significant emissions increase level of the controlling pollutant. Consequently, the contemporaneous emissions calculation has been conducted by comparing, on a plant-wide basis, the annual emissions from the existing facility with the projected annual emissions from the new facility.

SELECTION OF DATA FOR CONTEMPORANEOUS EMISSIONS CALCULATIONS

The year 1984 was selected, from the five year period preceding this application submittal, as the most representative year. Using actual operating data, the respective annual operating hours, fuel usage, and power production are as follows:

Boiler	ANNUAL OPERATING HOURS		FUEL USE		POWER PRODUCTION (10^6 KWH)
	Permitted	Actual	Nat Gas (10^6CF)	No. 6 Oil (10^3 Gal)	
6	840	12	0.0	0.374	.089
7	3,025	2,748.6	521.5	0.042	43.867
8	8,760	7,262.9	2,299.4	0.168	195.454

Emissions Calculations are based on the National Emissions Data System (NEDS) Source Classification Codes (SCC), according to the following formula:

Calculated Emissions (Tons/Year) =

$$\left[\left(\text{Annual Operating Rate for SCC}\right) \times \frac{\left(\text{Emission Factor from SCC File}\right)}{(2{,}000\ \text{lb/ton})} \times \left(\text{Fuel Parameter if applicable}\right) \times \left(\frac{100-\text{Control Efficiency }\%}{100}\right)\right]$$

where:

Annual Operating Rate = Millions of Cubic Feet of Natural Gas Burned/Yr

Emission Factor = Pounds of Pollutant/Million Cubic Feet of Gas Burned

Fuel Parameter = Ash or Sulfur Content of Fuel on Weight-by-Percent (%) Basis [Not Applicable for Combustion of Natural Gas]

Control Efficiency = Pollution Control Device Percent (%) Efficiency [Since No External Control Devices Are Included, This Factor Applies Only to NO_x]

A. ANNUAL OPERATING RATE

The preceeding table provides fuel consumption data for 1984.

B. EMISSION FACTORS

Emissions Factors
From NEDS SCC File

External Combustion Boilers - Electric Generation-4911

Pounds of Pollutant Emitted Per Unit Volume of Fuel Consumed		
Parameter	SCC 1-01-006-01 Natural Gas ($lb/10^6$ CF Burned)	SCC 1-01-004-04 No. 6 Oil ($lb/10^3$ gal Burned)
Particulates	3	13
SO_x	0.6	159 S
NO_x	550	42
VOC	1.4	0.76
CO	40	5

C. FUEL PARAMETERS

Not applicable for natural gas.

For No. 6 oil: Sulfur content as Percent

= 2.5% for No. 6 and No. 7 Boilers

= 0.75% for No. 8 Boiler

D. CONTROL EFFICIENCY

Not applicable.
Combining actual operating conditions with the appropriate NEDS emission factors, calculate the total actual annual emissions for each criteria pollutant.

ACTUAL EMISSIONS (T/Y)

PARAMETER		A	x	B	x	C	x	D	= ANNUAL EMISSIONS
Particulates									
No. 6	Gas	None							= 0 T/yr
	Oil	$\frac{0.374}{2000}$		13		2.5			= 0.0061 T/yr
No. 7	Gas	$\frac{521.5}{2000}$		3					= 0.78 T/yr
	Oil	$\frac{0.042}{2000}$		13		2.5			= 0.00068 T/Y
No. 8	Gas	$\frac{2299.4}{2000}$		3					= 3.45 T/yr
	Oil	$\frac{0.168}{2000}$		13		0.75			= 0.00082 T/yr
				Total Particulate Emissions					= 4.238 T/yr
Sulfur Dioxide									
No. 6	Gas	None							= 0 T/Yr
	Oil	$\frac{0.374}{2000}$		159.0		2.5			= 0.0743 T/yr
No. 7	Gas	$\frac{521.5}{2000}$		0.6					= 0.1565 T/yr
	Oil	$\frac{0.042}{2000}$		159.0		2.5			= 0.00835 T/yr

PARAMETER		A	x B	x C	x D	= ANNUAL EMISSIONS
No. 8	Gas	$\frac{2299.4}{2000}$	0.6			= 0.690 T/yr
	Oil	$\frac{0.168}{2000}$	159.0	0.75		= 0.01002 T/yr
			Total SO_x Emissions			= 0.93917 T/yr

Nitrogen Oxides

		A	B	C	D	= ANNUAL EMISSIONS
No. 6	Gas	None				= 0 T/yr
	Oil	$\frac{0.374}{2000}$	42			= 0.007854 T/yr
No. 7	Gas	$\frac{521.5}{2000}$	550			= 143.4125 T/yr
	Oil	$\frac{0.042}{2000}$	42			= 0.000882 T/yr
No. 8	Gas	$\frac{2299.4}{2000}$	550			= 632.335 T/yr
	Oil	$\frac{0.168}{2000}$	42			= 0.003528 T/yr
			Total NO_x Emissions			= 775.760 T/yr

Volatile Organic Compounds

		A	B	C	D	= ANNUAL EMISSIONS
No. 6	Gas					= 0 T/yr
	Oil	$\frac{0.374}{2000}$	0.76			= 0.000142 T/yr
No. 7	Gas	$\frac{521.5}{2000}$	1.4			= 0.36505 T/yr
	Oil	$\frac{0.042}{2000}$	0.76			= 0.0000159 T/yr

PARAMETER		A	x	B	x	C	x	D	= ANNUAL EMISSIONS
No. 8	Gas	$\frac{2299.4}{2000}$		1.4					= 1.60958 T/yr
	Oil	$\frac{0.168}{2000}$		0.76					= 0.0000638 T/yr
				Total VOC Emissions					= 1.9748517 T/yr

Carbon Monoxide

		A		B	=
No. 6	Gas				= 0 T/yr
	Oil	$\frac{0.374}{2000}$		5	= 0.000935 T/yr
No. 7	Gas	$\frac{521.5}{2000}$		40	= 10.43 T/yr
	Oil	$\frac{0.042}{2000}$		5	= 0.000105 T/yr
No. 8	Gas	$\frac{2299.4}{2000}$		40	= 45.98 T/yr
	Oil	$\frac{0.168}{2000}$		5	= 0.00042 T/yr
				Total CO Emissions	= 56.41146 T/yr

Summarizing the actual plant-wide emissions:

PRESENT ACTUAL EMISSIONS (T/Y)

	No. 6 12 hrs (0.07 wks)	No. 7 2748.6 hrs (16.3 wks)	No. 8 7262.9 hrs (43.2 wks)	**6,7,8 10023.5 hrs TOTAL**
Part	0.0061	0.781	3.451	**4.238**
SO_x	0.0743	0.16485	0.70002	**0.93917**
NO_x	0.007854	143.4134	632.338	**775.760**
VOC	0.000142	0.36507	1.6096	**1.974**
CO	0.0009	10.43	45.98	**56.41**

Following start-up of the new Unit 9, operation of the other units will be curtailed as follows:

	CURRENT OPERATING RATE (HRS/YR)	PROJECTED OPERATING RATE (HRS/YR)
Unit No. 6	12.0	12
Unit No. 7	2748.6	1344
Unit No. 8	7262.9	6384

Projected emissions for each pollutant can be calculated by multiplying present emissions, with the ratio of future total operating hours, to present operating hours.

PROJECTED EMISSIONS FOR THE MODIFIED PLANT

Unit No. 6: No change from 1984 emissions.

Unit No. 7: $\frac{\text{1344 hrs/yr future}}{\text{2748.6 hrs/yr present}}$ x present emissions = projected emissions for each pollutant

Unit No. 8: $\frac{\text{6384 hrs/yr future}}{\text{7262.9 hrs/yr present}}$ x present emissions = projected emissions for each pollutant

Unit No. 9: Refer to Attachment 4

Using the generic relationship for each unit, the projected emissions can be calculated as follows:

SUMMARY OF PROJECTED EMISSIONS (T/Y)							
	No.6 12 hrs (0.07 wks)	No. 7 1344 hrs (8 wks)	No. 8 6384 hrs (38 wks)	No. 9 6720 hrs (40 wks)	**6,7,8,9 14460 hrs TOTAL**	Net Emissions Increase	**Significant Emission Rate**
Part	0.0024	0.382	3.017	13.44	**16.841**	12.607	**25**
SO_x	0.0743	0.0806	0.612	0.567	**1.334**	0.395	**40**
NO_x	0.007854	70.126	552.86	172.52	**795.51**	19.75	**40**
VOC	0.000142	0.179	1.407	12.10	**13.69**	11.72	**40**
CO	0.0009	5.100	40.20	110.4	**155.7**	99.29	**100**

By comparing the present actual emissions for Units 6, 7, and 8 with the projected emissions for Units 6, 7, 8, and 9, the net emissions increase can be calculated as indicated in the above table. Since the increase of emissions of each criteria pollutant does not exceed the significant emission rate in the last column of the table, a new source review is not required.

#6 #7 #8	F + P
3.40	17.67
0.77	1.5729
622.99	942.760
1.59	14.07
45.30	169.08