# INTEROFFICE MEMORANDUM

**Sensitivity:** COMPANY CONFIDENTIAL

**Date:** 20-Aug-1999 11:10am
**From:** Jeff Koerner TAL
KOERNER_J
**Dept:** Air Resources Management
**Tel No:** 850/414-7268 GIC 069

**To:** Tom Davis ( tdavis@ectinc.com )
**To:** Paul Carpinone ( carpin@ix.netcom.com )

**Subject:** Hardee Power Station: New GE 7EA Combustion Turbine Project

Tom and Paul,

I received your updated information. For the DLN-1 combustor, it seems that GE is reluctant to guarantee CO emissions lower than 25 ppmvd when also guaranteeing a NOx emission standard of 9.0 ppmvd. I understand this is due to a few site-specific installations that had problems meeting a similar lower limit. However, GE was able to modify the combustor and meet the standard.

Although GE won't guarantee (yet) the lower CO emissions rates, the stack tests certainly suggest that emissions rates much lower than 25 ppmvd are achievable while meeting the 9 ppmvd standard. I believe your request to reduce CO emissions standard to 20 ppmvd is reasonable and makes the installation of an oxidation catalyst appear not quite cost effective in obtaining additional reductions. In consideration of possible problems during the initial installation including fine tuning the combustion turbine and perhaps modifying the combustor, I recommend the following specific permit condition.

12. Carbon Monoxide (CO)

(a) Dry-Low NOx Controls: During the first 12 months after initial startup, CO emissions shall not exceed 54.0 pounds per hour nor 25.0 ppmvd corrected to 15% oxygen based on a 3-hour test average when firing natural gas in the combustion turbine. Thereafter, CO emissions shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average when firing natural gas in the combustion turbine.

(b) Water Injection: When firing low sulfur distillate oil in the combustion turbine, CO emissions shall not exceed 46.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

Please provide any comments.

Jeff

# FACSIMILE TRANSMITTAL

TECO POWER SERVICES

702 North Franklin
Tampa, FL 33602

MAILING ADDRESS:
P. O. Box 111
Tampa, FL 33601

Phone: (813) 228-1675
Fax: (813) 228-1360

*PLEASE DELIVER IMMEDIATELY*

TO: Mr. Jeffery F. Koerner, P.E.

FROM: Paul L. Carpinone

DATE: August 18, 1999

RE: HARDEE POWER STATION
CT 2B PROJECT

MESSAGE:

Please call if you have any questions.

NUMBER OF PAGES (Including this cover page): 10
HARD COPY TO FOLLOW: YES
IF ANY PROBLEMS, CALL (813) 228-1675

CONFIDENTIALITY NOTE:
This message is intended only for the use of the individual or entity to which it is addressed, and may contain information that is privileged, confidential and exempt from disclosure under applicable law. If the reader of this message is not the intended recipient, or the employee or agent responsible for delivering the message to the intended recipient, you are hereby notified that any dissemination, distribution or copying of this communication is strictly prohibited. If you have received this communication in error, please notify us immediately by telephone, and return the original message to us at the above address via the U.S. Postal Service.

# HARDEE POWER PARTNERS

August 18, 1999

**BY FAX**

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: FDEP File No. PSD-FL-140(a);
TECO Power Services - Hardee Power Station;
Simple-Cycle (SC) CT2B Power Project

Dear Mr. Koerner:

Per our conversation, Hardee Power Partners (HPP) hereby submits revised BACT summary sheets (see attached) based on achieving a lower carbon monoxide (CO) concentration of 20 ppmvd during natural gas-firing for the proposed CT2B combustion turbine at Hardee Power Station.

As discussed, HPP has requested from GE a lower guaranteed CO emission rate than the 25 ppmvd CO concentration specified in the submitted permit application for natural gas-firing. The basis for this request was the finding that similar GE 7EA gas turbines, equipped with a 9 ppm NOx tuned DLN-1 combustion system, could produce on average a lower CO concentration than the 25 ppm guarantee level. In response to this request, however, GE was not willing to provide a guarantee for a lower CO emission rate, but would be willing to tune the combustion system, at the expense of HPP, to a lower value while maintaining the 9 ppm NOx emission concentration level.

As a result, HPP is willing to accept a CO permit limit of 20 ppmvd during natural gas-firing, along with a revised permit condition that would allow CT2B to operate while modifications or corrections, if needed, are being implemented. The condition would apply in the event that the 20 ppmvd CO concentration level is exceeded during any annual compliance test. This condition is being requested as a contingency due to the time required by GE to manufacture and re-tune the combustion system to achieve a lower CO level than the guaranteed emission rate of 25 ppmvd, if such modifications become necessary. For your convenience,

HARDEE POWER PARTNERS, LTD.
P. O. BOX 111 TAMPA, FL 33601-0111
AN EQUAL OPPORTUNITY COMPANY

(813) 228-1330
FAX (813) 228-1308
HTTP://WWW.TECOPOWERSERVICES.COM

I have attached proposed permit language revisions that we believe will allow us to achieve a lower CO emissions rate for this combustion turbine.

Your continued expeditious processing of the Hardee Power Station CT2B permit application is appreciated. Please contact me at 813-228-4858, if there are any further questions.

Sincerely,

Paul L. Carpinone

Paul L. Carpinone
Director, Environmental

Attachments

cc: H. S. Oven, FDEP, Tallahassee
L. N. Curtin, H&K, Tallahassee
T. W. Davis, ECT, Gainesville

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis — Signature

8/17/99 — Date

(seal)

* Attach any exception to certification statement.

**Certification is applicable to August 1999 information submittal regarding the Hardee Power Station Simple-Cycle Combustion Turbine Project.**

Table 5-12. Summary of CO BACT Analysis (Revised 8/99)

| Control Option | Emission Impacts: Emission Rates (lb/hr) | Emission Impacts: Emission Rates (tpy) | Emission Impacts: Emission Reduction (tpy) | Economic Impacts: Installed Capital Cost ($) | Economic Impacts: Total Annualized Cost ($/yr) | Economic Impacts: Cost Effectiveness Over Baseline ($/ton) | Energy Impacts: Increase Over Baseline (MMBtu/yr) | Environmental Impacts: Toxic Impact (Y/N) | Environmental Impacts: Adverse Envir. Impact (Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| Oxidation catalyst | 4.3 | 18.9 | 170.2 | 1,368,919 | 323,438 | 1,900 | 4,484 | Y | Y |
| Baseline | 43.2 | 189.1 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,884 hr/yr gas-firing and 876 hr/yr oil-firing.

Sources: GE, 1999.
ECT, 1999.

**Table 2. Hardee Power Station - CT2B (Revised 8/99)
CTG Operating Scenarios - General Electric PG7121(EA)
Natural Gas-Firing; Hourly Emission Rates**

| Temp. (°F) | Case | Load (%) | $PM/PM_{10}$ [1] (lb/hr) | $PM/PM_{10}$ [1] (g/sec) | $SO_2$ [2] (lb/hr) | $SO_2$ [2] (g/sec) | $H_2SO_4$ [3] (lb/hr) | $H_2SO_4$ [3] (g/sec) | Lead [4] (lb/hr) | Lead [4] (g/sec) |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | 1 | 100 | 5.0 | 0.63 | 5.7 | 0.72 | 0.655 | 0.0825 | 4.99E-04 | 6.29E-05 |
| | 2 | 75 | 5.0 | 0.63 | 4.6 | 0.58 | 0.526 | 0.0663 | 4.01E-04 | 5.05E-05 |
| | 3 | 65 | 5.0 | 0.63 | 4.2 | 0.53 | 0.486 | 0.0612 | 3.70E-04 | 4.66E-05 |
| 59 | 5 | 100 | 5.0 | 0.63 | 5.3 | 0.67 | 0.610 | 0.0768 | 4.65E-04 | 5.85E-05 |
| | 6 | 75 | 5.0 | 0.63 | 4.3 | 0.54 | 0.496 | 0.0624 | 3.78E-04 | 4.76E-05 |
| | 7 | 65 | 5.0 | 0.63 | 4.0 | 0.50 | 0.458 | 0.0577 | 3.49E-04 | 4.40E-05 |
| 95 | 9 | 100 | 5.0 | 0.63 | 4.8 | 0.60 | 0.550 | 0.0693 | 4.19E-04 | 5.28E-05 |
| | 10 | 75 | 5.0 | 0.63 | 4.0 | 0.50 | 0.454 | 0.0572 | 3.46E-04 | 4.36E-05 |
| | 11 | 65 | 5.0 | 0.63 | 3.7 | 0.46 | 0.420 | 0.0529 | 3.20E-04 | 4.03E-05 |
| | | **Maximums** | **5.0** | **0.63** | **5.7** | **0.72** | **0.655** | **0.0825** | **4.99E-04** | **6.29E-05** |

| Temp (°F) | Case | Load (%) | $NO_x$ (ppmvd) [5] | $NO_x$ (lb/hr) | $NO_x$ (g/sec) | CO (ppmvd) [5] | CO (lb/hr) | CO (g/sec) | VOC (ppmvd) [5] | VOC (lb/hr) | VOC (g/sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 32 | 1 | 100 | 9.0 | 35.0 | 4.41 | 19.6 | 45.6 | 5.75 | 1.5 | 2.0 | 0.25 |
| | 2 | 75 | 9.0 | 28.0 | 3.53 | 24.1 | 45.0 | 5.67 | 1.4 | 1.6 | 0.20 |
| | 3 | 65 | 9.0 | 25.0 | 3.15 | 24.0 | 40.0 | 5.04 | 1.4 | 1.4 | 0.18 |
| 59 | 5 | 100 | 9.0 | 32.0 | 4.03 | 19.8 | 43.2 | 5.44 | 1.5 | 1.8 | 0.23 |
| | 6 | 75 | 9.0 | 26.0 | 3.28 | 24.2 | 42.0 | 5.29 | 1.5 | 1.4 | 0.18 |
| | 7 | 65 | 9.0 | 24.0 | 3.02 | 24.1 | 39.0 | 4.91 | 1.5 | 1.4 | 0.18 |
| 95 | 9 | 100 | 9.0 | 29.0 | 3.65 | 19.9 | 39.2 | 4.94 | 1.5 | 1.8 | 0.23 |
| | 10 | 75 | 9.0 | 24.0 | 3.02 | 24.0 | 39.0 | 4.91 | 1.5 | 1.4 | 0.18 |
| | 11 | 65 | 9.0 | 22.0 | 2.77 | 24.3 | 36.0 | 4.54 | 1.5 | 1.2 | 0.15 |
| | | **Maximums** | **9.0** | **35.0** | **4.41** | **24.3** | **45.6** | **5.75** | **1.5** | **2.0** | **0.25** |

[1] Excludes sulfuric acid mist.
[2] Based on natural gas sulfur content of 2.0 gr/100 $ft^3$.
[3] Based on 7.5% conversion of $SO_2$ to $H_2SO_4$.
[4] Natural gas combustion, Table 1.4-2, AP-42, March 1998.
[5] Corrected to 15% $O_2$.

Sources: ECT, 1999.
GE, 1999.

Table 6A. Hardee Power Station - CT2B (Revised 8/99)
CTG Operating Scenarios - General Electric PG7121(EA)
Annual Emission Rates - Criteria Pollutants

| Source | Case | No. of CTGs | Annual Operations (hrs/yr) | Emission Rates $NO_x$ (lb/hr) | Emission Rates $NO_x$ (tpy) | CO (lb/hr) | CO (tpy) | VOC (lb/hr) | VOC (tpy) |
|---|---|---|---|---|---|---|---|---|---|
| CT2B | 5 - Gas | 1 | 7,884 | 32.0 | 126.1 | 43.2 | 170.3 | 1.8 | 7.1 |
| CT2B | 5 - Oil | 1 | 876 | 167.0 | 73.1 | 43.0 | 18.8 | 4.5 | 2.0 |
| | | | Totals | N/A | 199.3 | N/A | 189.1 | N/A | 9.1 |

| Source | Case | No. of CTGs | Annual Operations (hrs/yr) | Emission Rates $PM/PM_{10}$ (lb/hr) | Emission Rates $PM/PM_{10}$ (tpy) | $SO_2$ (lb/hr) | $SO_2$ (tpy) | Lead (lb/hr) | Lead (tpy) |
|---|---|---|---|---|---|---|---|---|---|
| CT2B | 5 - Gas | 1 | 7,884 | 5.0 | 19.7 | 5.3 | 20.9 | 0.0005 | 0.0018 |
| CT2B | 5 - Oil | 1 | 876 | 10.0 | 4.4 | 51.9 | 22.7 | 0.055 | 0.024 |
| | | | Totals | N/A | 24.1 | N/A | 43.7 | N/A | 0.026 |

1. CT2B operating with natural gas-firing at a 90.0% capacity factor; 7,884 hours/year at base load (Case 5).
2. CT2B operating with fuel oil-firing at a 10.0% capacity factor; 876 hours/year at base load (Case 5).
3. $SO_2$ rates based on natural gas sulfur content of 2.0 gr/100 $ft^3$.
4. $SO_2$ rates based on fuel oil sulfur content of 0.05 wt. percent.

Sources: GE, 1999.
ECT, 1999.
TPS, 1999.

# Table 8.C. Hardee Power Station - CT2B (Revised 8/99)
# CT Exhaust Data - General Electric PG7121(EA)
# Natural Gas-Firing; Simple-Cycle

## C. Correction of GE CO and VOC Concentrations to 15% $O_2$, dry

| | Flow Rates ($ft^3$/min) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 100 % Load | | | 75 % Load | | | 65 % Load | | |
| | 32 °F | 59 °F | 95 °F | 32 °F | 59 °F | 95 °F | 32 °F | 59 °F | 95 °F |
| Case | 1 | 5 | 9 | 2 | 6 | 10 | 3 | 7 | 11 |
| CO (ppmvd) | 20.0 | 20.0 | 20.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| CO (15% $O_2$) | 19.6 | 19.8 | 19.9 | 24.1 | 24.2 | 24.0 | 24.0 | 24.1 | 24.3 |
| VOC (ppmvw) | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| VOC (ppmvd) | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| VOC (15% $O_2$) | 1.5 | 1.5 | 1.5 | 1.4 | 1.5 | 1.5 | 1.4 | 1.5 | 1.5 |

Sources: ECT, 1999.
GE, 1999.

**EXHIBIT A REVISED 8/18/99**

**PROPOSED MODIFICATIONS OF CONDITIONS OF CERTIFICATION**
**HARDEE POWER STATION UNIT 2B**
**PA 89-25**

## EMISSION LIMITS AND STANDARDS

17. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for $NO_X$ are corrected to 15 % $O_2$ on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

| POLLUTANT | CONTROL TECHNOLOGY | PROPOSED BACT LIMIT |
|---|---|---|
| $PM/PM_{10}$, VE | Pipeline-Quality Natural Gas<br>Good Combustion | 10 Percent Opacity |
| VOC | As Above | 2 ppmvd (Gas)<br>4 ppmvd (Fuel Oil) |
| CO | As Above | 205 ppmvd (Gas)<br>20 ppmvd (Fuel Oil) |
| $SO_2$ | Pipeline-Quality Natural Gas<br>Low Sulfur Oil | 2 gr S/100 $ft^3$ (Gas)<br>0.05% S (Fuel Oil) |
| $NO_X$ | DLN, WI for F.O., limited fuel oil usage | 9 ppmv (Gas)<br>42 ppmv (Fuel Oil) - 876 Hours/Year Max. |

18. Nitrogen Oxides ($NO_X$) Emissions:

- When $NO_X$ monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of $NO_X$ in the exhaust gas shall not exceed 9 ppm @15% $O_2$ (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, $NO_X$ emissions calculated as $NO_2$ (at ISO conditions) shall not exceed 32 lb/hr and 9 ppm @15% $O_2$ to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of $NO_X$ in the exhaust gas shall not exceed 42 ppmvd at 15% $O_2$ on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, $NO_X$ emissions calculated as $NO_2$ (at ISO conditions) shall not exceed 167 lb/hr and 42 ppm @15% $O_2$ to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

19. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on either natural gas or distillate fuel oil shall exceed neither 205 ppmvd nor 4354 lb/hr to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.] Should any annual test demonstrate that CO emissions exceed either 20 ppmvd or 43 lb/hr, the Permittee shall submit either a request for a permit modification or a compliance schedule to achieve the 20 ppmvd and 43 lb/hr CO emission limits within thirty days following

submittal of the annual test results to the Department. A compliance schedule, if submitted, shall describe the corrective action proposed to comply with the 20 ppmvd and 43 lb/hr CO emission limits and include milestone implementation dates. Final compliance with the applicable CO emission limits shall occur no later than 12 months from the date of Department approval of the permit modification request or compliance schedule.

# HARDEE POWER PARTNERS

TECO POWER SERVICES

RECEIVED

AUG 19 1999

BUREAU OF AIR REGULATION

August 18, 1999

**BY FAX**

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: FDEP File No. PSD-FL-140(a);
TECO Power Services - Hardee Power Station;
Simple-Cycle (SC) CT2B Power Project

Dear Mr. Koerner:

Per our conversation, Hardee Power Partners (HPP) hereby submits revised BACT summary sheets (see attached) based on achieving a lower carbon monoxide (CO) concentration of 20 ppmvd during natural gas-firing for the proposed CT2B combustion turbine at Hardee Power Station.

As discussed, HPP has requested from GE a lower guaranteed CO emission rate than the 25 ppmvd CO concentration specified in the submitted permit application for natural gas-firing. The basis for this request was the finding that similar GE 7EA gas turbines, equipped with a 9 ppm NOx tuned DLN-1 combustion system, could produce on average a lower CO concentration than the 25 ppm guarantee level. In response to this request, however, GE was not willing to provide a guarantee for a lower CO emission rate, but would be willing to tune the combustion system, at the expense of HPP, to a lower value while maintaining the 9 ppm NOx emission concentration level.

As a result, HPP is willing to accept a CO permit limit of 20 ppmvd during natural gas-firing, along with a revised permit condition that would allow CT2B to operate while modifications or corrections, if needed, are being implemented. The condition would apply in the event that the 20 ppmvd CO concentration level is exceeded during any annual compliance test. This condition is being requested as a contingency due to the time required by GE to manufacture and re-tune the combustion system to achieve a lower CO level than the guaranteed emission rate of 25 ppmvd, if such modifications become necessary. For your convenience,

HARDEE POWER PARTNERS, LTD.
P. O. BOX 111 TAMPA, FL 33601-0111
AN EQUAL OPPORTUNITY COMPANY

(813) 228-1330
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I have attached proposed permit language revisions that we believe will allow us to achieve a lower CO emissions rate for this combustion turbine.

Your continued expeditious processing of the Hardee Power Station CT2B permit application is appreciated. Please contact me at 813-228-4858, if there are any further questions.

Sincerely,

Paul L. Carpinone

Paul L. Carpinone
Director, Environmental

Attachments

cc: H. S. Oven, FDEP, Tallahassee
L. N. Curtin, H&K, Tallahassee
T. W. Davis, ECT, Gainesville

cc: File
SWD
NPS
EPA

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis — 8/17/99

Signature — Date

(seal)

* Attach any exception to certification statement.

**Certification is applicable to August 1999 information submittal regarding the Hardee Power Station Simple-Cycle Combustion Turbine Project.**

Table 5-12. Summary of CO BACT Analysis (Revised 8/99)

| Control Option | Emission Impacts: Emission Rates (lb/hr) | Emission Impacts: Emission Rates (tpy) | Emission Impacts: Emission Reduction (tpy) | Economic Impacts: Installed Capital Cost ($) | Economic Impacts: Total Annualized Cost ($/yr) | Economic Impacts: Cost Effectiveness Over Baseline ($/ton) | Energy Impacts: Increase Over Baseline (MMBtu/yr) | Environmental Impacts: Toxic Impact (Y/N) | Environmental Impacts: Adverse Envir. Impact (Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| Oxidation catalyst | 4.3 | 18.9 | 170.2 | 1,368,919 | 323,438 | 1,900 | 4,484 | Y | Y |
| Baseline | 43.2 | 189.1 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,884 hr/yr gas-firing and 876 hr/yr oil-firing.

Sources: GE, 1999.
ECT, 1999.

## Table 2. Hardee Power Station - CT2B (Revised 8/99)
## CTG Operating Scenarios - General Electric PG7121(EA)
## Natural Gas-Firing; Hourly Emission Rates

| Temp. (°F) | Case | Load (%) | $PM/PM_{10}$ [1] (lb/hr) | $PM/PM_{10}$ [1] (g/sec) | $SO_2$ [2] (lb/hr) | $SO_2$ [2] (g/sec) | $H_2SO_4$ [3] (lb/hr) | $H_2SO_4$ [3] (g/sec) | Lead [4] (lb/hr) | Lead [4] (g/sec) |
|---|---|---|---|---|---|---|---|---|---|---|
| 32 | 1 | 100 | 5.0 | 0.63 | 5.7 | 0.72 | 0.655 | 0.0825 | 4.99E-04 | 6.29E-05 |
| | 2 | 75 | 5.0 | 0.63 | 4.6 | 0.58 | 0.526 | 0.0663 | 4.01E-04 | 5.05E-05 |
| | 3 | 65 | 5.0 | 0.63 | 4.2 | 0.53 | 0.486 | 0.0612 | 3.70E-04 | 4.66E-05 |
| 59 | 5 | 100 | 5.0 | 0.63 | 5.3 | 0.67 | 0.610 | 0.0768 | 4.65E-04 | 5.85E-05 |
| | 6 | 75 | 5.0 | 0.63 | 4.3 | 0.54 | 0.496 | 0.0624 | 3.78E-04 | 4.76E-05 |
| | 7 | 65 | 5.0 | 0.63 | 4.0 | 0.50 | 0.458 | 0.0577 | 3.49E-04 | 4.40E-05 |
| 95 | 9 | 100 | 5.0 | 0.63 | 4.8 | 0.60 | 0.550 | 0.0693 | 4.19E-04 | 5.28E-05 |
| | 10 | 75 | 5.0 | 0.63 | 4.0 | 0.50 | 0.454 | 0.0572 | 3.46E-04 | 4.36E-05 |
| | 11 | 65 | 5.0 | 0.63 | 3.7 | 0.46 | 0.420 | 0.0529 | 3.20E-04 | 4.03E-05 |
| | | **Maximums** | **5.0** | **0.63** | **5.7** | **0.72** | **0.655** | **0.0825** | **4.99E-04** | **6.29E-05** |

| Temp. (°F) | Case | Load (%) | $NO_x$ (ppmvd) [5] | $NO_x$ (lb/hr) | $NO_x$ (g/sec) | CO (ppmvd) [5] | CO (lb/hr) | CO (g/sec) | VOC (ppmvd) [5] | VOC (lb/hr) | VOC (g/sec) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 32 | 1 | 100 | 9.0 | 35.0 | 4.41 | 19.6 | 45.6 | 5.75 | 1.5 | 2.0 | 0.25 |
| | 2 | 75 | 9.0 | 28.0 | 3.53 | 24.1 | 45.0 | 5.67 | 1.4 | 1.6 | 0.20 |
| | 3 | 65 | 9.0 | 25.0 | 3.15 | 24.0 | 40.0 | 5.04 | 1.4 | 1.4 | 0.18 |
| 59 | 5 | 100 | 9.0 | 32.0 | 4.03 | 19.8 | 43.2 | 5.44 | 1.5 | 1.8 | 0.23 |
| | 6 | 75 | 9.0 | 26.0 | 3.28 | 24.2 | 42.0 | 5.29 | 1.5 | 1.4 | 0.18 |
| | 7 | 65 | 9.0 | 24.0 | 3.02 | 24.1 | 39.0 | 4.91 | 1.5 | 1.4 | 0.18 |
| 95 | 9 | 100 | 9.0 | 29.0 | 3.65 | 19.9 | 39.2 | 4.94 | 1.5 | 1.8 | 0.23 |
| | 10 | 75 | 9.0 | 24.0 | 3.02 | 24.0 | 39.0 | 4.91 | 1.5 | 1.4 | 0.18 |
| | 11 | 65 | 9.0 | 22.0 | 2.77 | 24.3 | 36.0 | 4.54 | 1.5 | 1.2 | 0.15 |
| | | **Maximums** | **9.0** | **35.0** | **4.41** | **24.3** | **45.6** | **5.75** | **1.5** | **2.0** | **0.25** |

[1] Excludes sulfuric acid mist.
[2] Based on natural gas sulfur content of 2.0 gr/100 $ft^3$.
[3] Based on 7.5% conversion of $SO_2$ to $H_2SO_4$.
[4] Natural gas combustion, Table 1.4-2, AP-42, March 1998.
[5] Corrected to 15% $O_2$.

Sources: ECT, 1999.
GE, 1999.

**Table 6A. Hardee Power Station - CT2B (Revised 8/99)**
**CTG Operating Scenarios - General Electric PG7121(EA)**
**Annual Emission Rates - Criteria Pollutants**

| Source | Case | No. of CTGs | Annual Operations (hrs/yr) | Emission Rates | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | $NO_x$ | | CO | | VOC | |
| | | | | (lb/hr) | (tpy) | (lb/hr) | (tpy) | (lb/hr) | (tpy) |
| CT2B | 5 - Gas | 1 | 7,884 | 32.0 | 126.1 | 43.2 | 170.3 | 1.8 | 7.1 |
| CT2B | 5 - Oil | 1 | 876 | 167.0 | 73.1 | 43.0 | 18.8 | 4.5 | 2.0 |
| | | | **Totals** | **N/A** | **199.3** | **N/A** | **189.1** | **N/A** | **9.1** |

| Source | Case | No. of CTGs | Annual Operations (hrs/yr) | Emission Rates | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | $PM/PM_{10}$ | | $SO_2$ | | Lead | |
| | | | | (lb/hr) | (tpy) | (lb/hr) | (tpy) | (lb/hr) | (tpy) |
| CT2B | 5 - Gas | 1 | 7,884 | 5.0 | 19.7 | 5.3 | 20.9 | 0.0005 | 0.0018 |
| CT2B | 5 - Oil | 1 | 876 | 10.0 | 4.4 | 51.9 | 22.7 | 0.055 | 0.024 |
| | | | **Totals** | **N/A** | **24.1** | **N/A** | **43.7** | **N/A** | **0.026** |

1. CT2B operating with natural gas-firing at a 90.0% capacity factor; 7,884 hours/year at base load (Case 5).
2. CT2B operating with fuel oil-firing at a 10.0% capacity factor; 876 hours/year at base load (Case 5).
3. $SO_2$ rates based on natural gas sulfur content of 2.0 gr/100 $ft^3$.
4. $SO_2$ rates based on fuel oil sulfur content of 0.05 wt. percent.

Sources: GE, 1999.
ECT, 1999.
TPS, 1999.

**Table 8.C. Hardee Power Station - CT2B (Revised 8/99)**
**CT Exhaust Data - General Electric PG7121(EA)**
**Natural Gas-Firing; Simple-Cycle**

**C. Correction of GE CO and VOC Concentrations to 15% $O_2$, dry**

| | Flow Rates ($ft^3$/min) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 100 % Load | | | 75 % Load | | | 65 % Load | | |
| | 32 °F | 59 °F | 95 °F | 32 °F | 59 °F | 95 °F | 32 °F | 59 °F | 95 °F |
| Case | 1 | 5 | 9 | 2 | 6 | 10 | 3 | 7 | 11 |
| CO (ppmvd) | 20.0 | 20.0 | 20.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| CO (15% $O_2$) | 19.6 | 19.8 | 19.9 | 24.1 | 24.2 | 24.0 | 24.0 | 24.1 | 24.3 |
| VOC (ppmvw) | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| VOC (ppmvd) | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| VOC (15% $O_2$) | 1.5 | 1.5 | 1.5 | 1.4 | 1.5 | 1.5 | 1.4 | 1.5 | 1.5 |

Sources: ECT, 1999.
GE, 1999.

**EXHIBIT A REVISED 8/18/99**

**PROPOSED MODIFICATIONS OF CONDITIONS OF CERTIFICATION**
**HARDEE POWER STATION UNIT 2B**
**PA 89-25**

## EMISSION LIMITS AND STANDARDS

17. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for $NO_X$ are corrected to 15 % $O_2$ on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

| POLLUTANT | CONTROL TECHNOLOGY | PROPOSED BACT LIMIT |
|---|---|---|
| $PM/PM_{10}$, VE | Pipeline-Quality Natural Gas<br>Good Combustion | 10 Percent Opacity |
| VOC | As Above | 2 ppmvd (Gas)<br>4 ppmvd (Fuel Oil) |
| CO | As Above | 20~~5~~ ppmvd (Gas)<br>20 ppmvd (Fuel Oil) |
| $SO_2$ | Pipeline-Quality Natural Gas<br>Low Sulfur Oil | 2 gr S/100 $ft^3$ (Gas)<br>0.05% S (Fuel Oil) |
| $NO_X$ | DLN, WI for F.O., limited fuel oil usage | 9 ppmv (Gas)<br>42 ppmv (Fuel Oil) - 876 Hours/Year Max. |

18. Nitrogen Oxides ($NO_X$) Emissions:

- When $NO_X$ monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of $NO_X$ in the exhaust gas shall not exceed 9 ppm @15% $O_2$ (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, $NO_X$ emissions calculated as $NO_2$ (at ISO conditions) shall not exceed 32 lb/hr and 9 ppm @15% $O_2$ to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of $NO_X$ in the exhaust gas shall not exceed 42 ppmvd at 15% $O_2$ on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, $NO_X$ emissions calculated as $NO_2$ (at ISO conditions) shall not exceed 167 lb/hr and 42 ppm @15% $O_2$ to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

19. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on either natural gas or distillate fuel oil shall exceed neither 20~~5~~ ppmvd nor 43~~54~~ lb/hr to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.] Should any annual test demonstrate that CO emissions exceed either 20 ppmvd or 43 lb/hr, the Permittee shall submit either a request for a permit modification or a compliance schedule to achieve the 20 ppmvd and 43 lb/hr CO emission limits within thirty days following

submittal of the annual test results to the Department. A compliance schedule, if submitted, shall describe the corrective action proposed to comply with the 20 ppmvd and 43 lb/hr CO emission limits and include milestone implementation dates. Final compliance with the applicable CO emission limits shall occur no later than 12 months from the date of Department approval of the permit modification request or compliance schedule.

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

AUG 11 1999

RECEIVED
AUG 16 1999
BUREAU OF AIR REGULATION

4 APT-ARB

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

SUBJ: Application to Modify Certification for Hardee Power Partners, Ltd.
Hardee Power Station PA 89-25 located in Wauchula, FL

Dear Mr. Linero:

Thank you for sending an application to modify Hardee Power station as well as proposed modifications to the Conditions of Certification dated June 4, 1999, for the above referenced facility. The application is for a proposed installation of one simple cycle combustion turbine (CT) with a nominal generating capacity of 75 MW. The CT will combust pipeline quality natural gas as its primary fuel and distillate fuel oil as a backup fuel. As proposed, the turbine will be allowed to operate 8,760 hours per year with up to 876 hours per year firing fuel oil. Emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides ($NO_X$), carbon monoxide (CO), sulfur dioxide ($SO_2$) and particulate matter ($PM/PM_{10}$).

The combustion turbine proposed for the facility is a General Electric (GE) Model PG7121 (EA) unit (frequently referred to as a GE 7EA turbine). The proposed best available control technology (BACT) for $NO_X$ emissions is use of a dry low-$NO_X$ (DLN) combustor. Based on our review of the application, we have the following comments:

1. The proposed BACT limit, found on page 5-11, for particulate matter ($PM_{10}$) is 10% opacity of visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT limit for particulate matter emissions rate. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions also should list the corresponding emission rate (i.e., 0.002 gr/dscf).

2. For your information, there is an inconsistency in the permit application regarding the \$/ton cost of CO oxidation catalyst control. On page 5-17, in section 5.4.3, the cost effectiveness of oxidation catalyst control for CO emissions is listed as \$1,644 per ton of CO removed. However, in table 5-12 (pg. 5-21), cost effectiveness is listed as \$1,551 per ton of CO removed.

3. As indicated on page 2-4 of the permit application, Hardee Power is requesting allowable excess emissions due to startup, shutdown or malfunction for up to 4 hours in any 24-hour period. This proposal is inconsistent with FDEP's preliminary determination for Kissimmee Utility's Cane Island Power Park (January 1999) which only allowed excess emissions from a simple cycle combustion turbine for 1 hour in any 24-hour period. Additionally, Hardee Power will operate the new combustion turbine as part of their baseload operation. Therefore, the reduced number of startups and shutdowns should minimize the need for allowable excess emissions. Finally, it is the Environmental Protection Agency's (EPA's) policy (see January 28, 1993 memo from John B. Rasnic to Region 1) that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

4. The new combustion turbine, which will fire No. 2 fuel oil as backup fuel, has the potential to increase the throughput of the existing fuel oil storage tank. Any increase in VOC emissions from the additional use should be taken into account when calculating the potential to emit of VOC emissions. We realize the VOC emissions increase will be small and do not expect it to cause any applicability changes; however, as a matter of completeness, this increase in emissions should be included in all PTE calculations.

5. In the SCR cost analysis, an interest rate of 7.5 percent was used to calculate a capital recovery factor. This interest rate may be appropriate for Hardee Power Station; however, it should be noted that the OAQPS Control Cost Manual uses an interest rate of 7 percent.

6. The cost analysis for SCR uses $NO_X$ emissions of 9 ppm as the baseline and calculates the cost effectiveness of using SCR with controlled $NO_X$ emissions at an assumed level of 3.5 ppm. In other words, the applicant does not base tons per year reduced on a specific control efficiency value. We note that the applicant's approach yields a control efficiency of about 61 percent, which is at the low end of the control efficiencies we have previously seen for SCR control.

7. If you plan to use any portion of the applicant's proposed permit conditions, we recommend the phrase "per year" be changed to "per consecutive 12 months."

Thank you for the opportunity to comment on the Hardee Power Station permit application. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

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

cc: J. Koerner, BAR
T. Davis, ECT
B. Oven, PPS
NPS
SWD

Author: Kim Pierce at REGION4 Bridgette
Date: 8/12/99 2:12 PM
Priority: Urgent
TO: Karen Cody
Subject: TA RETURNED WITHOUT ACTION- FOR KIM PIERCE

FYI.

Forward Header

Subject: TA RETURNED WITHOUT ACTION- FOR KIM PIERCE
Author: Barbara Grant at REGION4
Date: 8/12/1999 2:09 PM

Bridgett,

I received a RUSH TA for Kim stating that she was using a POV for traveling to Lagrange. When you use POV, you must justify it in block 10E on the TA.

Please pick up the document immediately and make adjustments then return to Budget's in box to be restamped and processed.

Thanks, bjg

ARMS Data Related to GE Model 7EA CT'S

8-12-99

Gainesville Regional Utilities - Deerhaven Station

ARMS ID No. 001-0006

EU #006, GE 7001EA, 74MW SCCT

Test Data:

NOx Allowable: 15ppmvd (gas)

CO Allowable: Unknown

NOx Measured: 8.9 ppmvd 3/1/96

8.6 ppmvd 3/4/96

7.25 ppmvd 6/2/97

6.7 ppmvd 5/28/98

CO Measured: 7.1 ppmvd

Kissimmee Utility Authority - Cane Island Power Partners

ARMS ID No. 097-0043

EU -002, GE 7EA (7111EA), 75MW CCCT (Al Linero verified)

Test Data:

NOx Allowable: 25 ppmvd

CO Allowable: 20 ppmvd

NOx Measured: 10.5 ppmvd 11-13-95

CO Measured: 9.7 ppmvd 11-13-9

8.5 ppmvd 6-4-96

# Fax Cover Sheet

8-11-99

TO: Jeff Koerner

from: Katy Forney

RE: Hardee Power Station

---

Here you go Jeff. Call me w/ questions

Katy

404-562-9130

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

4 APT-ARB

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

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Sincerely,

Douglas Neeley

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

**ECT**

**Environmental Consulting & Technology, Inc.**

RECEIVED

JUL 23 1999

BUREAU OF AIR REGULATION

July 22, 1999
ECT No. 990462-0100

**SENT BY OVERNIGHT MAIL ON 7/22/99**

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

**Re: Florida Department of Environmental Protection (FDEP)**
**File No. PSD-FL-140(a); PA89-25**
**TECO Power Services; Hardee Power Station; CT2B Power Project**

Dear Mr. Koerner:

On behalf of TECO Power Services (TPS), the following responses are provided to the items raised in your July 15, 1999 correspondence:

**Item 1. Combustor Type and Description**

The proposed combustion turbine CT2B, a General Electric (GE) PG7121 7EA unit, will be equipped with GE's DLN-1 combustor technology. GE technical literature describing the DLN-1 combustor technology is included as Attachment I.

**Item 2. Combustion Control System Description**

The GE 7EA unit will be controlled by means of GE's SPEEDTRONIC™ Mark V gas turbine control system. GE technical literature describing the Mark V control system is provided as Attachment II.

**Item 3. Manufacture Emission Guarantees**

A written guarantee of $NO_x$ and CO emissions from the combustion turbine manufacturer (GE) is provided as Attachment III. Performance curves illustrating $NO_x$ and CO emissions as a function of load are included in the GE technical literature provided in Attachment I.

3701 Northwest
98[TH] Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

**Item 4. Emissions Test Data for a Similar GE 7EA Unit**

A copy of stack test results for a similar GE 7EA unit (i.e., dual-fuel, DLN-1 combustor unit) is provided as Attachment IV. These test results were obtained from two GE 7EA units located at the Panda-Brandywine Cogeneration Facility in Brandywine, Maryland.

**Item 5. Dispersion Modeling Output Files**

It is understood that electronic copies of the dispersion modeling output files are no longer required.

As advised in my e-mail message to you today, Table 7-13 (dispersion modeling summary) of the submitted application inadvertently indicated the unadjusted model results (i.e., based on a nominal 10.0 g/s emission rate) rather than the adjusted model results. Accordingly, Attachment V provides a revised version of Table 7-13. Note that the correct, adjusted model results are considerably lower than the unadjusted concentrations.

Your continued expeditious processing of the TECO Power Services Hardee Power Station CT2B project will be appreciated. Please contact me at 352/332-6230, Ext.351, if there are any further questions.

Sincerely,

**ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.**

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Attachments

cc: Mr. Paul Carpinone, P.E., TPS
Mr. Lawrence Curtin, Holland & Knight

CC: EPA
NPS
Buck Oven, PPS
SD
File

# ATTACHMENT I

# GE DLN-1 COMBUSTOR TECHNICAL LITERATURE

# DRY LOW $NO_x$ COMBUSTION SYSTEMS FOR GE HEAVY-DUTY GAS TURBINES

L.B. Davis
GE Power Systems
Schenectady, NY

## ABSTRACT

State-of-the-art emissions control technology for heavy-duty gas turbines is reviewed with emphasis on the operating characteristics and field experience of Dry Low $NO_x$(DLN) combustors for E- and F- technology machines. The lean premixed DLN systems for gas fuel have demonstrated their ability to meet the ever-lower emission levels required today. Lean premixed technology has also been demonstrated on oil fuel and is also discussed.

## INTRODUCTION

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 10 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of $NO_x$ and other pullutants from both new and existing gas turbines. Traditional methods of reducing $NO_x$ emissions from combustion turbines (water and steam injection)are limited in their ability to reach the extremely low levels required in many localities. GE's involvement in the development of both the traditional methods (References 1 through6) and the newer Dry Low $NO_x$(DLN) technology (References 7 and 8) has been well-documented. This paper focuses on DLN.

Since the commercial introduction of GE's DLN combustion systems for natural-gas-fired heavy-duty gas turbines in 1991, systems have been installed in more than 145 machines, from the most modern F technology (firing temperature class of 2400 F/1316 C) to field retrofits of older machines. As of August 1996, these machines have operated more than one million hours with DLN; more than 290,000 hours have been in the F technology. To meet marketplace demands, GE has developed DLN products broadly classified as either DLN-1, which was developed for E-technology (2000 F/1093C firing temperature class) machines, or DLN-2, which was developed specifically for the F technology machines and is also being applied to the EC, G and H machines.

Development of these products has required an intensive engineering effort involving both GE Power Systems and GE Corporate Research and Development. This collaboration will continue as DLN is applied to the G and H machines and combustor development for Dry Low $NO_x$ on oil ("dry oil") continues.

This paper presents the current status of DLN-1 technology and experience, including dry oil, and of DLN-2 technology and experience. Background information about gas turbine emissions and emissions control is contained in the Appendix.

## DRY LOW $NO_X$ SYSTEMS

### Dry Low $NO_X$ Product Plan

Figure 1 shows GE's Dry Low $NO_x$ product offerings for its new and existing machines in three major groupings. The first group includes the MS3000, MS5000 and MS6001B products. The 6B DLN-1 is the technology flagship product for this group and, as can be noted, is available to meet 9 ppm $NO_x$ requirements. Such low $NO_x$ emissions are generally not attainable on lower firing temperature machines such as the MS3000s and MS5000s because carbon monoxide (CO) would be excessive.

The second major group includes the MS7000B/E, MS7001EA and MS9001E machines with the 9 ppm 7EA DLN-1 as the flagship product. The dry oil program focuses initially on this group.

The third group combines all of the DLN-2 products and includes the FA, EC, G and H machines, with the 7FA product as the flagship.

As shown in Figures 2 and 3, most of these products are capable of power augmentation and of peak firing with increased $NO_x$ emissions. With gas fuel, power augmentation with steam is in the premixed mode for both DLN-1 and DLN-2 systems. Power augmentation with water is in the lean-lean mode for DLN-1 and in the premixed mode for DLN-2.

The GE DLN systems integrate a staged premixed combustor, the gas turbine's SPEEDTRONICTM controls and the fuel and associated systems. There

| | Gas | | | Distillate | | |
|---|---|---|---|---|---|---|
| Turbine Model | $NO_x$ (ppmvd) | CO (ppmvd) | Diluent | $NO_x$ (ppmvd) | CO (ppmvd) | Diluent |
| MS3002 (J) - RC | 33 | 25 | Dry | Not Available | | |
| MS3002 (J) - SC | 42 | 50 | Dry | | | |
| MS5001P | 42 | 50 | Dry | 65 | 20 | Water |
| MS5001R | 42 | 50 | Dry | 65 | 20 | Water |
| MS5002C | 42 | 50 | Dry | 65 | 20 | Water |
| MS6001B | 25 | 15 | Dry | 42 | 20 | Water |
| | 9 | 25 | Dry | 42 | 30 | Water/Steam |
| MS7001B/E Conv. | 25 | 25 | Dry | 42 | 30 | Water |
| MS7001EA | 25 | 15 | Dry | 42 | 20 | Water |
| | 15 | 25 | Dry | 42 | 30 | Water/Steam |
| | 9 | 25 | Dry | 42 | 30 | Water/Steam |
| MS9001E | 35 | 15 | Dry | 42 | 20 | Water |
| | 25 | 25 | Dry | 42 | 20 | Water |
| | 25 | 25 | Dry | 90 | 20 | Dry |
| MS6001FA | 25 | 15 | Dry | 42/65 | 20 | Water/Steam |
| MS7001FA | 25 | 15 | Dry | 42/65 | 20 | Water/Steam |
| | 9 | 9 | Dry | 42/65 | 30 | Water/Steam |
| MS7001H | 25 | 15 | Dry | 42/65 | 20 | Water/Steam |
| | 9 | 9 | Dry | 42/65 | 30 | Water/Steam |
| MS9001EC | 25 | 15 | Dry | 42/65 | 20 | Water/Steam |
| MS9001FA | 25 | 15 | Dry | 42/65 | 20 | Water/Steam |
| MS9001H | 25 | 15 | Dry | 42/65 | 20 | Water/Steam |

Notes: 1. $No_x$ levels are at 15% oxygen. Ambient range 30 F/-1 C to 100 F/30 C

GT24717E

**Figure 1. Dry Low $No_x$ product plan**

are two principal measures of performance. The first is meeting the emission levels required at base load on both gas and oil fuel and controlling the variation of these levels across the load range of the gas turbine.

The second measure is system operability, with

| Turbine Model | $NO_x$ @15% $O_2$ (ppmvd) | Operating Mode | Diluent | Maximum Diluent/Fuel | $NO_x$ at Max D/F (ppmvd) | CO Max D/F (ppmvd) |
|---|---|---|---|---|---|---|
| MS6001(B) | 9 | Premix | Steam | 2.5/1 | 9 | 25 |
| | | Lean-Lean | Steam | 2.5/1 | 25 | 15 |
| | 25 | Premix | Steam | 2.5/1 | 25 | 15 |
| | | Lean-Lean | Water | 1.5/1 | 25 | 15 |
| | | Lean-Lean | Steam | 2.5/1 | 25 | 15 |
| MS7001(EA) | 9 | Premix | Steam | 2.5/1 | 9 | 25 |
| | | Lean-Lean | Water | 1.5/1 | 25 | 15 |
| | | Lean-Lean | Steam | 2.5/1 | 25 | 15 |
| | 25 | Premix | Steam | 2.5/1 | 25 | 15 |
| | | Lean-Lean | Water | 1.5/1 | 25 | 15 |
| | | Lean-Lean | Steam | 2.5/1 | 25 | 15 |
| MS7001(FA) | 25 | Premix | Steam | 2.1/1 | 25 | 15 |

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**Figure 2. DLN power augmentation summary - gas fuel**

| | $NO_x$-Base (ppmvd) | $NO_x$-Peak (ppmvd) | CO-Base (ppmvd) | CO-Peak (ppmvd) |
|---|---|---|---|---|
| MS6001(B) | 9<br>25 | 18<br>50 | 25<br>15 | 6<br>4 |
| MS7001(EA) | 9<br>25 | 18<br>50 | 25<br>15 | 6<br>4 |
| MS7001(FA) | 25 | 35 | 15 | 6 |
| MS9001(E) | 25 | 40 | 15 | 6 |

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**Figure 3. DLN peak firing summary - gas fuel**

emphasis placed on the smoothness and reliability of combustor mode changes, ability to load and unload the machine without restriction, capability to switch from one fuel to another and back again, and system response to rapid transients (e.g., generator breaker open events or rapid swings in load). GE's design goal is to make the DLN system operate so the gas turbine operator does not know whether a DLN or conventional combustion system is installed (i.e., its operation is "transparent to the user"). As of August 1996, a significant portion of the DLN design and development effort has focused on system operability.

Design of a successful DLN combustor for a heavy-duty gas turbine also requires the designer to develop hardware features and operational methods that simultaneously allow the equivalence ratio and residence time in the flame zone to be low enough to achieve low $NO_x$, but with acceptable levels of combustion noise (dynamics), stability at part load operation and sufficient residence time for CO burn-out, hence the designation of DLN combustion design as "four-sided box" (Figure 4).

A scientific and engineering development program by GE's Corporate Research and Development Center, Power Systems business and Aircraft Engine business has focused on understanding and controlling dynamics in lean premixed flows. The objectives have been to:

- Gather and analyze machine and laboratory data to create a comprehensive dynamics data base
- Create analytical models of gas turbine combustion systems that can be used to understand dynamics behavior
- Use the analytical models and experimental methods to develop methods to control dynamics

As of August 1996, these efforts have resulted in a large number of hardware and control features that limit dynamics, plus analytical tools that are used to predict system behavior. The latter are particularly useful in correlating laboratory test data from full scale combustors with actual gas turbine data.

## DLN-1 System

DLN-1 development began in the 1970s with the goal of producing a dry oil system to meet the United States Environmental Protection Agency's New Source Performance Standards of 75 ppmvd $NO_x$ at 15% $O_2$. As noted in Reference 7, this system was tested on both oil and gas fuel at Houston Lighting & Power in 1980 and met its emission goals. Subsequent to this, DLN program goals changed in response to stricter environmental regulations and the pace of the program accelerated in the late 1980s.

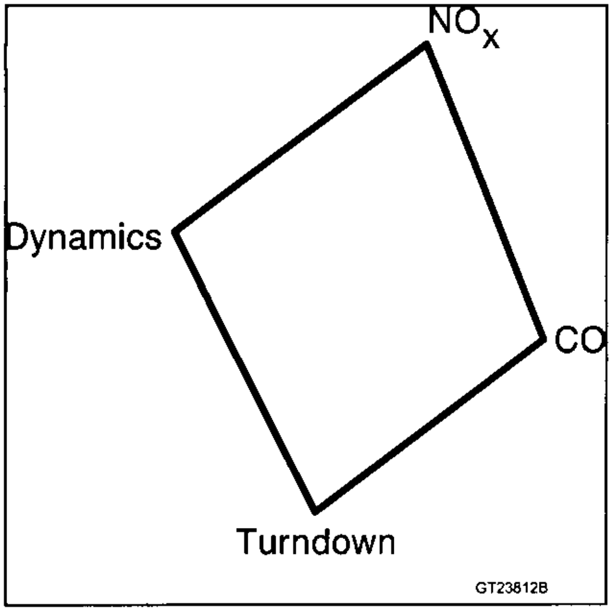


**Figure 4. DLN technology - a four-sided box**

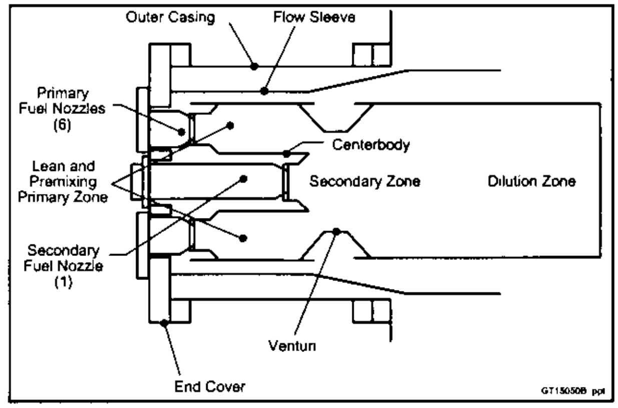


**Figure 5. DLN-1 combustor schematic**

## DLN-1 Combustor

The GE DLN-1 combustor (shown in cross section in Figure 5 and described in Reference 8) is a two-stage premixed combustor designed for use with natural gas fuel and capable of operation on liquid fuel. As shown, the combustion system includes four major components: fuel injection system, liner, venturi and cap/centerbody assembly.

These components form two stages in the combustor. In the premixed mode, the first stage thoroughly mixes the fuel and air and delivers a uniform, lean, unburned fuel-air mixture to the second stage.

The GE DLN-1 combustion system operates in four distinct modes, illustrated in Figure 6, during pre-mixed natural gas or oil fuel operation:

| Mode | Operating Range |
|---|---|
| Primary | Fuel only to the primary nozzles. Flame is in the primary stage only. This mode of operation is used to ignite, accelerate and operate the machine over low- to mid-loads, up to a preselected combustion reference temperature. |
| Lean-Lean | Fuel to both the primary and secondary nozzles. Flame is in both the primary and secondary stages. This mode of operation is used for intermediate loads between two preselected combustion reference temperatures. |
| Secondary | Fuel to the secondary nozzle only. Flame is in the secondary zone only. This mode is a transition state between lean-lean and premix modes. This mode is necessary to extinguish the flame in the primary zone, before fuel is reintroduced into what becomes the primary premixing zone. |
| Premix | Fuel to both primary and secondary nozzles. Flame is in the secondary stage only. This mode of operation is achieved at and near the combustion reference temperature design point. Optimum emissions are generated in premix mode. |

The load range associated with these modes varies with the degree of inlet guide vane modulation and, to a smaller extent, with the ambient temperature. At ISO ambient, the premix operating range is 50% to 100% load with IGV modulation down to 42 Degrees, and 75% to 100% load with IGV modulation down to 57 Degrees. The 42 Degrees IGV minimum requires an inlet bleed heat system.

If required, both the primary and secondary fuel nozzles can be dual-fuel nozzles, thus allowing automatic transfer from gas to oil throughout the load range. When burning either natural gas or distillate oil, the system can operate to full load in the lean-lean mode (Figure 6) and in the pre-mixed. Power augmentation with water is the most common reason.

The spark plug and flame detector arrangements in a DLN-1 combustor are different from those used in a conventional combustor. Since the first stage must be re-ignited at high load in order to transfer from the

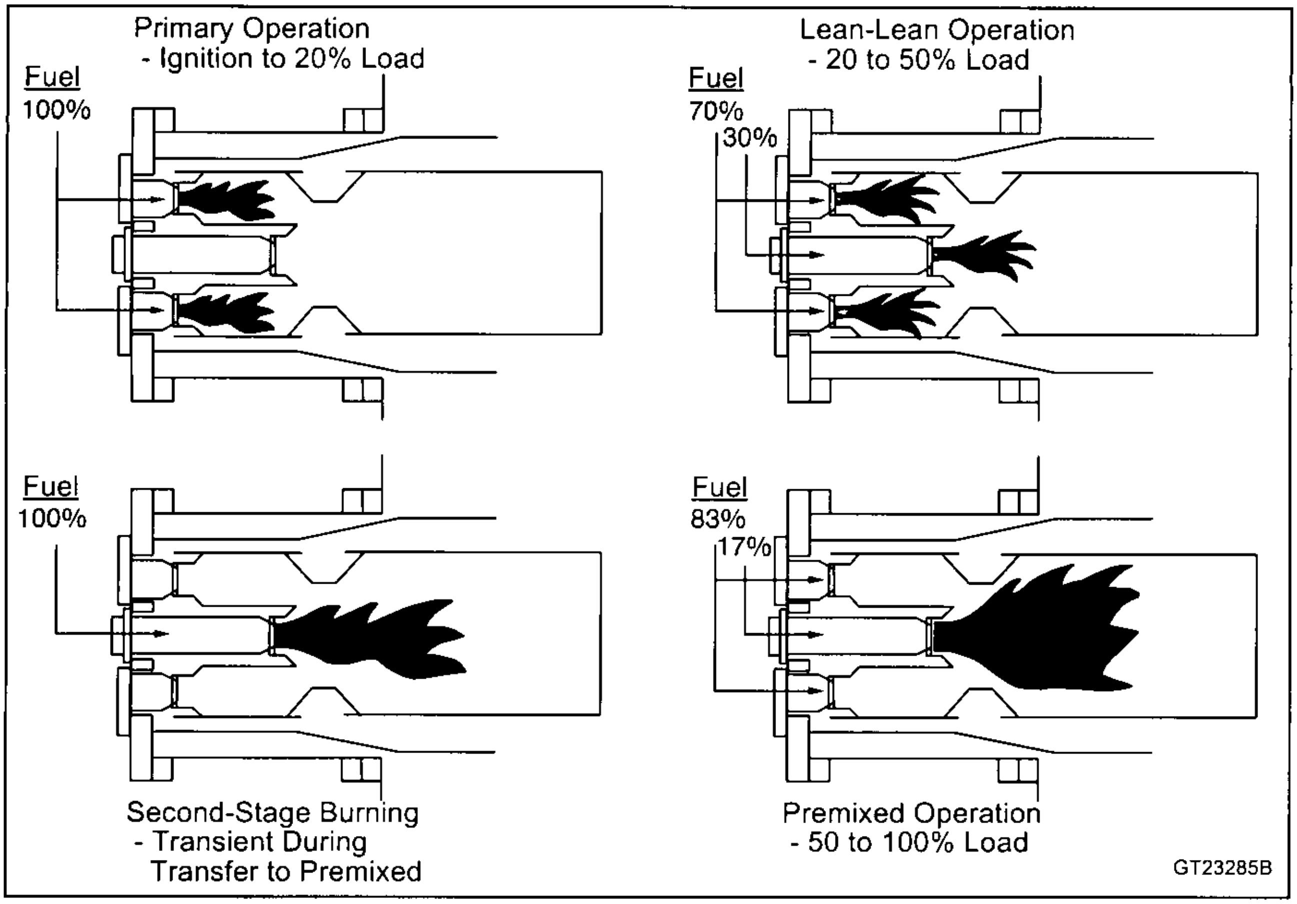


**Figure 6. Fuel-staged Dry Low NOx operating modes**

premixed mode back to lean-lean operation, the spark plugs do not retract. One plug is mounted in a primary zone cup in each of two combustors. The system uses flame detectors to view the primary stage of selected chambers (similar to conventional systems), and secondary flame detectors that look through the centerbody and into the second stage.

The primary fuel injection system is used during ignition and part load operation. The system also injects most of the fuel during premixed operation and must be capable of stabilizing the flame. For this reason, the DLN-1 primary fuel nozzle is similar to GE's MS7001EA multi-nozzle combustor with multiple swirl-stabilized fuel injectors. The GE DLN-1 system uses five primary fuel nozzles for the MS6001B and smaller machines and six primary fuel nozzles for the larger machines. This design is capable of providing a well-stabilized diffusion flame that burns efficiently at ignition and during part load operation.

In addition, the multi-nozzle fuel injection system provides a satisfactory spatial distribution of fuel flow entering the first-stage mixer. The primary fuel-air mixing section is bound by the combustor first-stage wall, the cap/centerbody and the forward cone of the venturi. This volume serves as a combustion zone when the combustor operates in the primary and lean-lean modes. Since ignition occurs in this stage, crossfire tubes are installed to propagate flame and to balance pressures between adjacent chambers. Film slots on the liner walls provide cooling, as they do in a standard combustor.

In order to achieve good emissions performance in premixed operation, the fuel-air equivalence ratio of the mixture exiting the first-stage mixer must be very lean. Efficient and stable burning in the second stage is achieved by providing continuous ignition sources at both the inner and outer surfaces of this flow. The three elements of this stage comprise a piloting flame, an associated aerodynamic device to force interaction between the pilot flame and the inner surface of the main stage flow, and an aerodynamic device to create a stable flame zone on the outer surface of the main stage flow exiting the first stage.

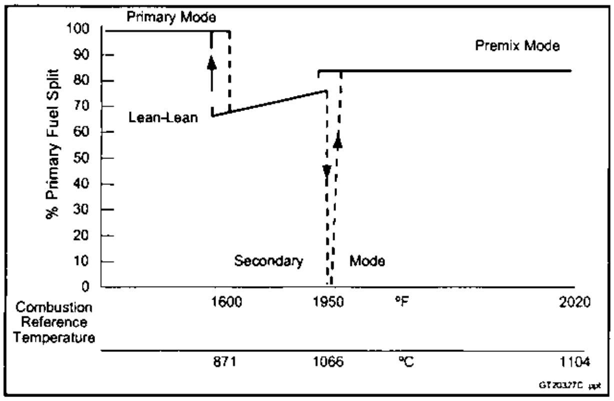


**Figure 7. Typical Dry Low Nox fuel gas split schedule**

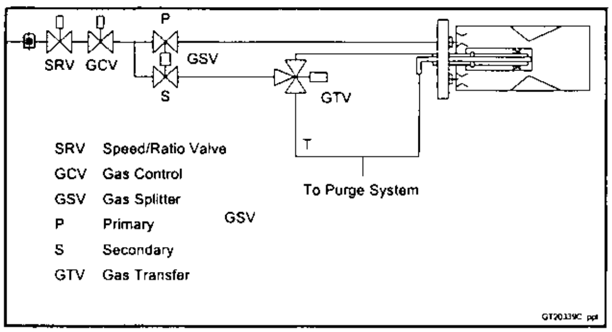


**Figure 8. DLN-1 gas fuel system**

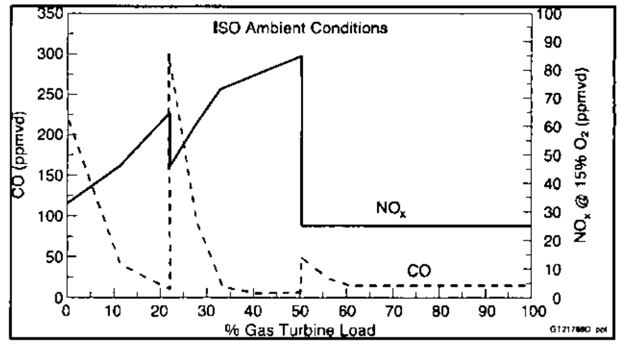


**Figure 9. MS7001EA/MS9001E DLN-1 combustion system performance on natural gas fuel**

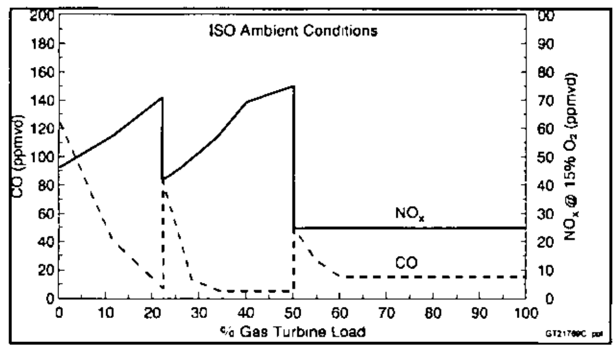


**Figure 10. MS6001B DLN-1 emissions performance on natural gas fuel**

The piloting flame is generated by the secondary fuel nozzle, which premixes a portion of the natural gas fuel and air (nominally, 17% at full-load operation) and injects the mixture through a swirler into a cup where it is burned. This flame is stabilized by burning an even smaller amount of fuel (less than 2% of the total fuel flow) as a diffusion flame in the cup. The secondary nozzle, which is mounted in the cap centerbody, is simple and highly effective for creating a stable flame.

A swirler mounted on the downstream end of the cap/centerbody surrounds the secondary nozzle. This creates a swirling flow that stirs the interface region between the piloting flame and the main-stage flow and ensures that the flame is continuously propagated from the pilot to the inner surface of the fuel-air mixture exiting the first stage. Operation on oil fuel is similar except that all of the secondary oil is burned in a diffusion flame in the current dry oil design.

The sudden expansion at the throat of the venturi creates a toroidal recirculation zone over the downstream conical surface of the venturi. This zone, which entrains a portion of the venturi cooling air, is a stable burning zone that acts as an ignition source for the main stage fuel-air mixture. The cone angle and axial location of the venturi cooling air dump have significant effects on the efficacy of this ignition source. Finally, the dilution zone (the region of the combustor immediately downstream from the flame zone in the secondary) provides a region for CO burnout and for shaping the gas temperature profile exiting the combustion system.

## DLN-1 Controls and Accessories

The gas turbine accessories and control systems are configured so that operation on a DLN-equipped turbine is essentially identical to that of a turbine equipped with a conventional combustor. This is accomplished by controlling the turbines in identical fashions, with the exhaust temperature, speed and compressor discharge pressure establishing the fuel flow and compressor inlet guide vane position.

A turbine with a conventional diffusion combustor that uses diluent injection for $NO_x$ control will use an underlying algorithm to control steam or water injection. This algorithm will use top level control variables (exhaust temperature, speed, etc.) to establish a steam-to-fuel or water-to-fuel ratio to control $NO_x$.

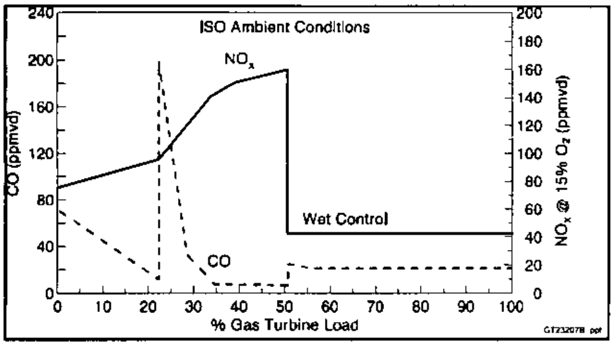


**Figure 11. MS7001EA/MS9001E DLN-1 combustion system performance on distillate oil**

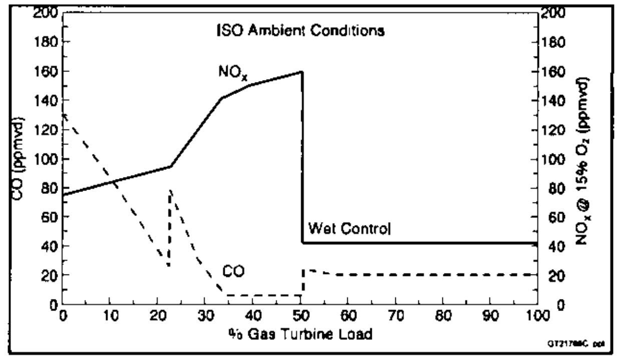


**Figure 12. MS6001B DLN-1 emissions performance on distillate oil fuel**

In a similar fashion, the same variables are used to divide the total turbine fuel flow between the primary and secondary stages of a DLN combustor. The fuel division is accomplished by commanding a calibrated splitter valve to move to a set position based on the calculated combustion reference temperature (Figure 7). Figure 8 shows aschematic of the gas fuel system for a DLN-equipped turbine.

The only special control sequences required are concerned protection of the turbine during a generator breaker-open trip, or flashback, from the second stage to the first stage during premixed operation. When either the breaker opens at load or flashback is sensed by ultraviolet flame detectors looking into the first stage, the splitter valve is commanded to move to a pre-determined position. In the case of a flashback, the control system can execute an automatic sequence to return to premixed, full-load operation.

## DLN-1 Emissions

The emissions performance of the GE DLN system can be illustrated as a function of load for a given ambient temperature and turbine configuration. Figures 9 and 10 show the $NO_x$ and CO emissions from typical MS7001EA and MS6001B DLN systems designed for 9 ppmvd $NO_x$ and 25 ppm CO when operated on natural gas fuel. Note that in premixed operation, $NO_x$ is generally highest at higher loads and CO only approaches 25 ppm at lower premixed loads.

Figures 11 and 12 show $NO_x$ and CO emissions for the same systems operated on oil fuel with water injection for $NO_x$ control, rather than premixed oil. These figures are for units equipped with inlet bleed heat and extended IGV modulation. $NO_x$ and CO emissions from the DLN combustor at loads less than 20% of base load are similar to those from standard combustion systems. This result is expected because both systems are operating as diffusion flame combustors in this range. Between 20% and 50% load, the DLN system is operated in the lean-lean mode, and the flow split between the primary fuel nozzles and secondary nozzle is varied to give the decreasing $NO_x$ characteristic shown.

From 50%to 100%load, the DLNsystem operates as a lean premixed combustor. As shown in Figures 9 through 12, $NO_x$ emissions are significantly reduced, while CO emissions are comparable to those from the standard system.

## DLN-1 Experience

GE's first DLN-1 system was tested at Houston Lighting & Power in 1980 (Reference 7). A prototype DLN system using the combustor design discussed above was tested on an MS9001E at the Electricity Supply Board's (ESB) Northwall Station in Dublin, Ireland, between October 1989 and July 1990. A comprehensive engineering test of the prototype DLN combustor, controls and associated systems was conducted with $NO_x$ levels of 32 ppmvd (at 15% $O_2$) obtained at base load. The results were incorporated into the design of prototype systems for the MS7001E and MS6001B.

The 7E DLN-1 prototype was tested at Anchorage Municipal Light and Power (AMLP) in early 1991 and entered commercial service shortly afterward. Since then, development of advanced combustor configurations have been carried out at AMLP. These results have been incorporated into production hardware.

The MS6001B prototype system was first operated at Jersey Central Power & Light's Forked River Station in early 1991. A series of additional tests culminated in the demonstration of a 9 ppm combustor at Jersey Central in November 1993.

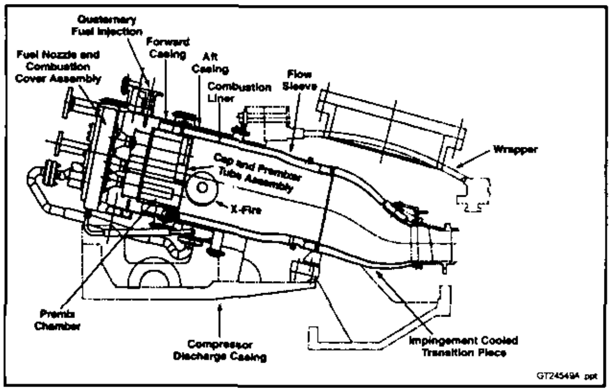


**Figure 13. DLN-2 combustion system**

As of August 1996, 28 MS6001B machines are equipped with DLN-1 systems. In total, they have accumulated more than 370,000 hours of operation. There are, in addition, four MS7001E, eight MS7001B-E, 26 MS7001EA, 18 MS9001E, one MS5001P and three MS3002J DLN-1 machines that have collectively operated for more than 350,000 hours. Excellent emission results have been obtained in all cases, with single-digit $NO_x$ and COachieved on several MS7001EAs. Several MS7001E/EA machines have the capability to power augment with either massive water or steam injection.

Starting in early 1992, eight MS7001F machines equipped with GE DLN systems were placed in service at Korea Electric Power Company's Seoinchon site. These F technology machines have achieved better than 55% (gross) efficiency in combined-cycle operation, and the DLN systems are currently operating between 30 and 40 ppmvd $NO_x$ on gas fuel (the guarantee level is 50 ppmvd). These units have operated for more than 150,000 hours. Four additional F technology DLN-1 systems have been commissioned at Scottish Hydro's Keadby site and at National Power's Little Barford site. These 9F machines have operated more than 20,000 hours at less than 60 ppm $NO_x$.

The combustion laboratory testing and field operation have shown that the DLN-1 system can achieve single digit $NO_x$ and CO levels on E technology machines operating on gas fuel. Current DLN-1 development activity focuses on four goals:

- Application of single-digit technology to the MS6001B, MS7001EA and MS9001E
- Application of DLN-1 technology for retrofitting existing field machines (including MS3002s and MS5000s, some of which will require upgrade before DLN retrofit)

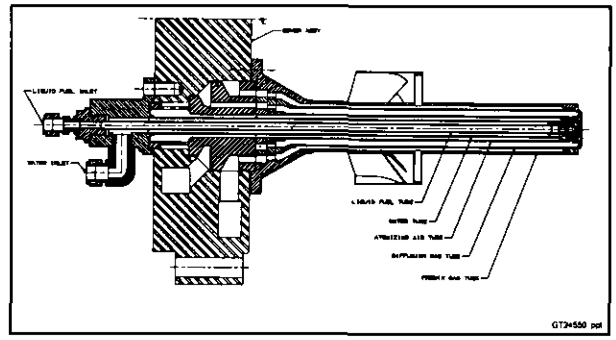

**Figure 14. Cross-section of a DLN-2 fuel nozzle**

- Completing the development of steam and water power augmentation as needed by the market
- Completing the development of dry oil DLN-1 products.

# DLN-2 SYSTEM

As F-technology gas turbines became available in the late 1980s, studies were conducted to establish what type of DLN combustor would be needed for these new higher firing temperature machines. Studies concluded that that air usage in the combustor (e.g., for cooling) other than for mixing with fuel would have to be strictly limited. A team of engineers from GE Power Generation, GE Corporate Research and Development and GE Aircraft Engine proposed a design that repackaged DLN-1 premixing technology but eliminated the venturi and centerbody assemblies that require cooling air.

The resulting combustor is called DLN-2, which is the standard system for the 6FA, 7FA, 9FA, 9EC, 7G, 7H, 9G and 9H machines. Fourteen combustors are installed in the 7FA and 9EC, 18 in the 9FA, and six in the 6FA. These combustors, for all but the 7FA, are not scaled, but are full-size 9FA combustors; the 7FA is slightly smaller.

## DLN-2 Combustion System

The DLN-2 combustion system shown in Figure 13 is a single-stage dual-mode combustor that can operate on both gaseous and liquid fuel. On gas, the combustor operates in a diffusion mode at low loads (< 50% load), and a premixed mode at high loads (> 50% load). While the combustor can operate in the diffusion mode across the load range, diluent injection would be required for $NO_x$ abatement. Oil operation on this combustor is in the diffusion mode

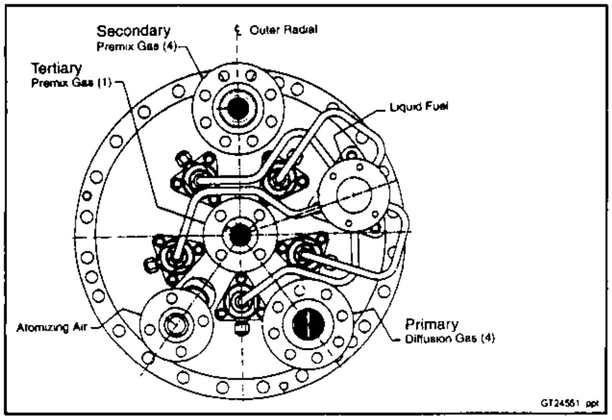


**Figure 15. External view of DLN-2 fuel nozzles mounted**

across the entire load range, with diluent injection used for $NO_X$ control.

Each DLN-2 combustor system has a single burning zone formed by the combustor liner and the face of the cap. In low emissions operation, 90% of the gas fuel is injected through radial gas injection spokes in the premixer, and combustion air is mixed with the fuel in tubes surrounding each of the five fuel nozzles. The premixer tubes are part of the cap assembly. The fuel and air are thoroughly mixed, flow out of the five tubes at high velocity and enter the burning zone where lean, low- $NO_x$ combustion occurs. The vortex breakdown from the swirling flow exiting the premixers, along with the sudden expansion in the liner, are mechanisms for flame stabilization. The DLN-2 fuel nozzle/premixer tube arrangement is similar in design and technology to the secondary nozzle/centerbody of a DLN-1. Five nozzle/premixer tube assemblies are located on the head end of the combustor. A quaternary fuel manifold is

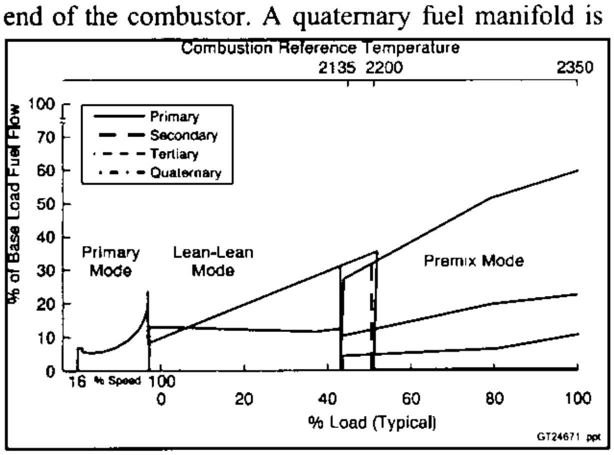


**Figure 16. Fuel flow scheduling associated with DLN-2 operation**

located on the circumference of the combustion casing to bring the remaining fuel flow to casing injection pegs located radially around the casing.

Figure 14 shows a cross-section of a DLN-2 fuel nozzle. As noted, the nozzle has passages for diffusion gas, premixed gas, oil and water. When mounted on the end cover, as shown in Figure 15, the diffusion passages of four of the fuel nozzles is fed from a common manifold, called the primary, that is built into the end cover. The premixed passage of the same four nozzles are fed from another internal manifold called the secondary. The premixed passages of the remaining nozzle are supplied by the tertiary fuel system; the diffusion passage of that nozzle is always purged with compressor discharge air and passes no fuel.

Figure 15 shows the fuel nozzles installed on the combustion chamber end cover and the connections for the primary, secondary and tertiary fuel systems. DLN-2 fuel streams are:

- Primary fuel – fuel gas entering through the diffusion gas holes in the swirler assembly of each of the outboard four fuel nozzles
- Secondary fuel – premix fuel gas entering through the gas metering holes in the fuel gas injector spokes of each of the outboard four fuel nozzles
- Tertiary fuel – premix fuel gas delivered by the metering holes in the fuel gas injector spokes of the inboard fuel nozzle
- The quaternary system – injects a small amount of fuel into the airstream just upstream from the fuel nozzle swirlers

The DLN-2 combustion system can operate in several different modes.

### Primary

Fuel only to the primary side of the four fuel nozzles; diffusion flame. Primary mode is used from ignition to 81% corrected speed.

### Lean-Lean

Fuel to the primary (diffusion) fuel nozzles and single tertiary (premixing) fuel nozzle. This mode is used from 81% corrected speed to a preselected combustion reference temperature. The percentage of primary fuel flow is modulated throughout the range of operation as a function of combustion reference temperature. If necessary, lean-lean mode can be operated throughout the entire load range of the turbine. Selecting "lean-lean base on" locks out premix operation and enables the machine to be taken to base load in lean-lean.

**Premix Transfer**

Transition state between lean-lean and premix modes. Throughout this mode, the primary and secondary gas control valves modulate to their final position for the next mode. The premix splitter valve is also modulated to hold a constant tertiary flow split.

**Piloted Premix**

Fuel is directed to the primary, secondary and tertiary fuel nozzles. This mode exists while operating with temperature control off as an intermediate mode between lean-lean and premix mode. This mode also exists as a default mode out of premix mode and, in the event that premix operating is not desired, piloted premix can be selected and operated to base load. Primary, secondary and tertiary fuel split are constant during this mode of operation.

**Premix**

Fuel is directed to the secondary, tertiary and quaternary fuel passages and premixed flame exists in the combustor. The minimum load for premixed operation is set by the combustion reference temperature and IGV position. It typically ranges from 50% with inlet bleed heat on to 65% with inlet bleed heat off. Mode transition from premix to piloted premix or piloted premix to premix, can occur whenever the combustion reference temperature is greater than 2200 F/1204 C. Optimum emissions are generated in premix mode.

**Tertiary Full Speed No Load (FSNL)**

Initiated upon a breaker open event from any load greater than 12.5%. Fuel is directed to the tertiary nozzle only and the unit operates in secondary FSNL mode for a minimum of 20 seconds, then transfers to lean-lean mode.

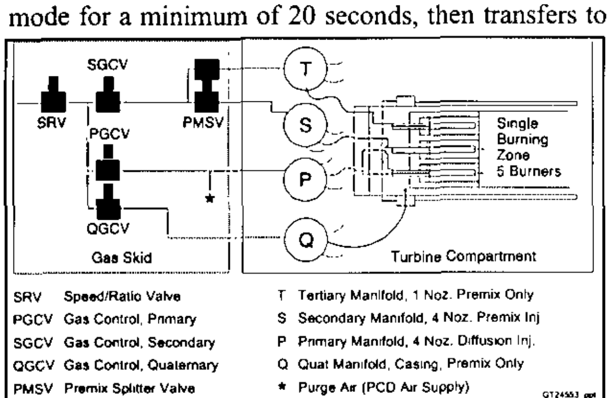


**Figure 17. DLN-2 gas fuel system**

Figure 16 illustrates the fuel flow scheduling associated with DLN-2 operation. Fuel staging depends on combustion reference temperature and IGV temperature control operation mode.

## DLN-2 Controls and Accessories

The DLN-2 control system regulates the fuel distribution to the primary, secondary, tertiary and quaternary fuel system. The fuel flow distribution to each combustion fuel system is a function of combustion reference temperature and IGV temperature control mode. Diffusion, piloted premix and premix flame are established by changing the distribution of fuel flow in the combustor. The gas fuel system (Figure 17) consists of the gas fuel stop/ratio valve, primary gas control valve, secondary gas control valve premix splitter valve and quaternary gas control valve. The stop/ratio valve is designed to maintain a predetermined pressure at the control valve inlet.

The primary, secondary and quaternary gas control valves regulate the desired gas fuel flow delivered to the turbine in response to the fuel command from the SPEEDTRONICTM controls.

The premix splitter valve controls the fuel flow split between the secondary and tertiary fuel system.

## DLN-2 Emissions Performance

Figures 18 and 19 show the emissions performance for a DLN-2 equipped 7FA/9FA for gas fuel and for oil fuel with water injection.

## DLN-2 Experience

The first DLN-2 systems were placed in service at Florida Power and Light's Martin Station with com-

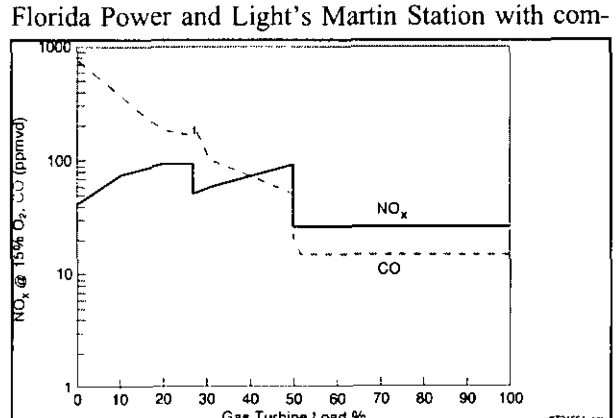


**Figure 18. Emissions performance for DLN-2-equipped 7FA/9FA for gas fuel**

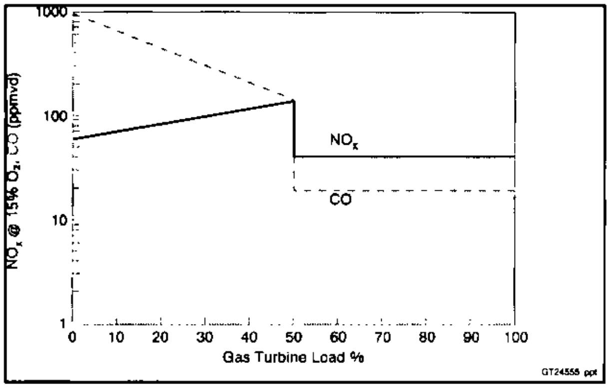


**Figure 19. Emissions performance for DLN-2-equipped 7FA/9FA for oil fuel with water injection**

missioning beginning in September 1993, and the first two (of four) 7FA units entering commercial service in February 1994. During commissioning, quaternary fuel was added and other combustor modifications were made to control dynamic pressure oscillations in the combustor.

As of August 1996, 23 DLN-2 7FA and 17 9FA units are in commercial service. They have accumulated more than 150,000 hours of operation. Of these units, 11 are dual-fuel units, and the remainder are gas-only.

# CONCLUSION

GE's Dry Low $NO_x$ Program continues to focus on the development of systems capable of the extremely low $NO_x$ levels required to meet today's regulations and to prepare for more stringent requirements in the future. New unit production needs and the requirements of existing machines, are being addressed. GE DLN systems are operating on more than 145 machines and have accumulated more than one million service hours. More than 200 DLN systems have been either put into service, shipped or placed on order. GE is the only manufacturer with F technology machines operating below 25 ppmvd.

# APPENDIX

## Gas Turbine Combustion Systems

A gas turbine combustor mixes large quantities of fuel and air and burns the resulting mixture. In concept the combustor is comprised of a fuel injector and a wall to contain the flame. There are three fundamental factors and practical concerns that complicate the design of the combustor: equivalence ratio, flame stability, and ability to operate from ignition through full load.

### Equivalence ratio

A flame burns best when there is just enough fuel to react with the available oxygen. With this stoichiometric mixture (equivalence ratio of 1.0) the flame temperature is the highest and the chemical reactions are the fastest, compared to cases where there is either more oxygen ("fuel lean," < 1.0) or less oxygen ("fuel rich," > 1.0) for the amount of fuel present.

In a gas turbine, the maximum temperature of the hot gases exiting the combustor is limited by the tolerance of the turbine nozzles and buckets. This temperature corresponds to an equivalence ratio of 0.4 to 0.5 (40 to 50% of the stoichiometric fuel flow). In the combustors used on modern gas turbines, this fuel-air mixture would be too lean for stable and efficient burning. Therefore, only a portion of the compressor discharge air is introduced directly into the combustor reaction zone (flame zone) to be mixed with the fuel and burned. The balance of the airflow either quenches the flame prior to the combustor discharge entering the turbine or to cool the wall of the combustor.

### Flame Stability

Even with only part of the air being introduced into the reaction zone, flow velocities in the zone are higher than the turbulent flame speed at which a flame propagates through the fuel-air mixture. Special mechanical or aerodynamic devices must be used to stabilize the flame by providing a low velocity region. Modern combustors employ a combination of swirlers and jets to achieve a good mix and to stabilize the flame.

### Operational Stability

The combustor must be able to ignite and to support acceleration and operation of the gas turbine over the entire load range of the machine. For a single-shaft generator-drive machine, speed is constant under load and, therefore, so is the airflow for a fixed ambient temperature. There will be a five- or six-to-one turndown in fuel flow over the load range, and a combustor whose reaction zone equivalence ratio is optimized for full load operation will be very lean at the lower loads. Nevertheless, the flame must be sta-

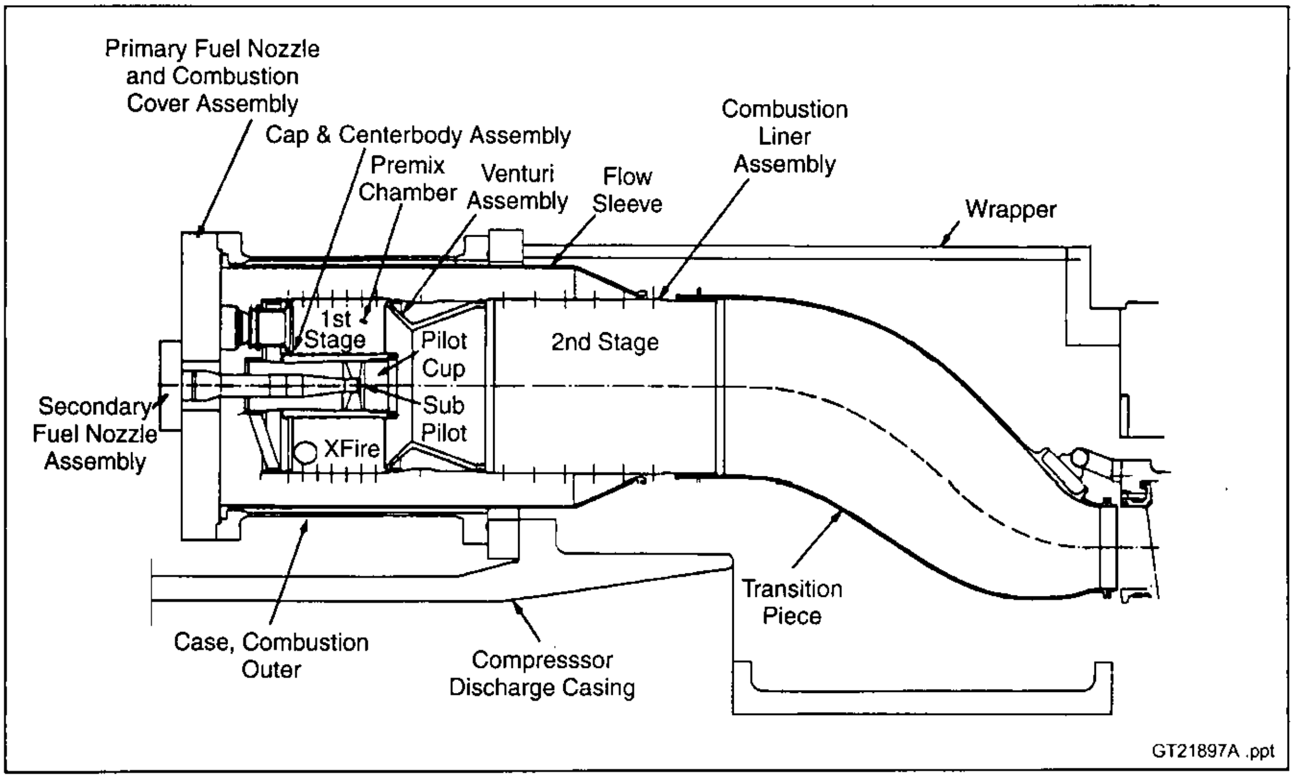


**Figure A1. MS7001EA Dry Low Nox combustion chamber**

ble and the combustion process must be efficient at all loads.

GE uses multiple-combustion chamber assemblies in its heavy-duty gas turbines to achieve reliable and efficient turbine operation. As shown in Figure A-1, each combustion chamber assembly comprises a cylindrical combustor, a fuel injection system and a transition piece that guides the flow of the hot gas from the combustor to the inlet of the turbine. Figure A-2 illustrates the multiple-combustor concept.

There are several reasons for using the multiple-chamber arrangement instead of large silo-type combustors:

- The configuration permits the entire turbine to be factory assembled, tested and shipped without interim disassembly
- The turbine inlet temperature can be better controlled, thus providing for longer turbine life with reduced turbine cooling air requirements
- Smaller parts can be handled more easily during routine maintenance
- Smaller transition pieces are less susceptible to damage from dynamic forces generated in the combustor; furthermore, the shorter combustion system length ensures that acoustic natural frequencies are higher and less likely to couple with the pressure oscillations in the flame
- Smaller combustors generate less $NO_x$ because of much better mixing and shorter residence time
- As turbine inlet temperatures have increased to improve efficiency, the size of the combustors has decreased to minimize cooling requirements, as in aircraft gas turbine combustors
- Small can-type combustors can be completely developed in the laboratory through a combination of both atmospheric and full-pressure, full-flow tests. Therefore, there is a higher degree of confidence that a combustor will perform as designed across all load ranges before it is installed and tested in a machine.

## Gas Turbine Emissions

The significant products of combustion in gas turbine emissions are:

- Oxides of nitrogen (NO and $NO_2$, collectively called $NO_x$)
- Carbon monoxide (CO)
- Unburned hydrocarbons or UHCs (usually expressed as equivalent methane ($CH_4$) particles and arise from incomplete combustion)

• Oxides of sulfur ($SO_2$ and $SO_3$) particulates.

Unburned hydrocarbons include both volatile organic compounds (VOCs), which contribute to the formation of atmospheric ozone, and compounds, such as methane, that do not.

There are two sources of $NO_x$ emissions in the exhaust of a gas turbine. Most of the $NO_x$ is generated by the fixation of atmospheric nitrogen in the flame, which is called thermal $NO_x$. Nitrogen oxides are also generated by the conversion of a fraction of any nitrogen chemically bound in the fuel (called fuel-bound nitrogen or FBN). Lower-quality distillates and low-Btu coal gases from gasifiers with hot gas cleanup carry various amounts of fuel-bound nitrogen that must be taken into account when emissions calculations are made. The methods described below to control thermal $NO_x$ emissions are ineffective in controlling the conversion of FBN to $NO_x$.

Thermal $NO_x$ is generated by a chemical reaction sequence called the Zeldovich Mechanism (Reference 6). This set of well-verified chemical reactions postulates that the rate of generation of thermal $NO_x$ is an exponential function of the temperature of the flame. The amount of $NO_x$ generated is a function of the flame temperature and of the time the hot gas mixture is at flame temperature. This turns out to be a linear function of time. Thus, temperature and residence time determine thermal $NO_x$ emissions levels and are the principal variables that a gas turbine designer can adjust to control emission levels.

For a given fuel, since the flame temperature is a unique function of the equivalence ratio, the rate of $NO_x$ generation can be cast as a function of the equivalence ratio. Figure A-3, shows that the highest rate of $NO_x$ production occurs at an equivalence ratio of 1.0, when the temperature is equal to the stoichiometric, adiabatic flame temperature.

To the left of the maximum temperature point (Figure A-3), more oxygen is available (the equivalence ratio is less than 1.0) and the resulting flame

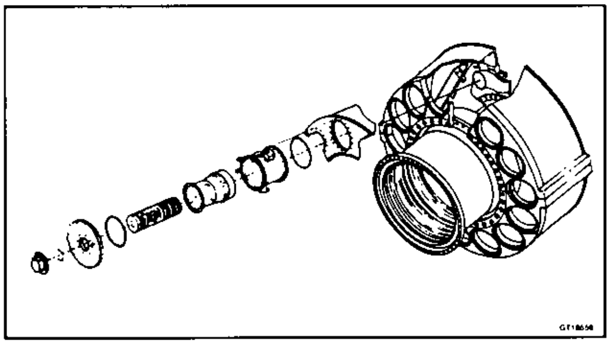

**Figure A2. Exploded view of combustion chamber**

temperature is lower. This is a fuel-lean operation. Since the rate of $NO_x$ formation is a function of temperature and time, it follows that some difference in $NO_x$ emissions can be expected when different fuels are burned in a given combustion system. Since distillate oil and natural gas have approximately a 100F/38 C flame temperature difference, a significant difference in $NO_x$ emissions can be expected if reaction zone equivalence ratio, water injection rate, etc. are equal.

As shown in Figure A-3, the rate of $NO_x$ production dramatically decreases as flame temperature decreases (i.e., the flame becomes fuel lean). This is because of the exponential effect of temperature in the Zeldovich Mechanism and is the reason why diluent injection (usually water or steam) into a gas turbine combustor flame zone reduces $NO_x$ emissions. For the same reason, very lean dry combustors can be used to control emissions. This is desirable for reaching the lower $NO_x$ levels now required in many applications.

There are two design challenges associated with very lean combustors. First, care must be taken to ensure that the flame is stable at the design operating point. Secondly, a turndown capability is necessary since a gas turbine must ignite, accelerate, and operate over the load range. At lower loads, as fuel flow to the combustors decreases, the flame will be very lean and will not burn well, or it can become unstable and blow out.

In response to these challenges, combustion system designers use staged combustors so a portion of the flame zone air can mix with the fuel at lower loads or during startup. The two types of staged combustors are fuel-staged and air-staged (Figure A-4). In its simplest and most common configuration, a fuel-staged combustor has two flame zones; each receives a constant fraction of the combustor airflow. Fuel flow is divided between the two zones so that at each machine operating condition, the amount of fuel fed to a stage matches the amount of air available.

An air-staged combustor uses a mechanism for diverting a fraction of the airflow from the flame zone to the dilution zone at low load to increase turndown. These methods can be combined.

## Emissions Control Methods

There are three principal methods for controlling gas turbine emissions:

- Injection of a diluent such as water or steam into the burning zone of a conventional (diffusion flame) combustor
- Catalytic clean-up of $NO_x$ and CO from the gas turbine exhaust (usually used in conjunction with the other two methods)
- Design of the combustor to limit the formation of pollutants in the burning zone by utilizing "lean-premixed" combustion technology.

The last method includes both DLN combustors and catalytic combustors. GE has considerable experience with each of these three methods.

Since September 1979, when regulations required that $NO_x$ emissions be limited to 75 ppmvd (parts per million by volume, dry), more than 300 GE heavy-duty gas turbines have accumulated more than 2.5 million operating hours using either steam or water-injection to meet or exceed these required $NO_x$ emissions levels. The amount of water required to accomplish this is approximately one-half of the fuel flow. However, there is a 1.8% heat-rate penalty associated with using water to control $NO_x$ emissions for oil-fired simple-cycle gas turbines. Output, increases by approximately 3%, making water (or steam) injection for power augmentation economically attractive in some circumstances (such as peaking applications).

Single-nozzle combustors that use water or steam injection are limited in their ability to reduce $NO_x$ levels below 42 ppmvd on gas fuel and 65 ppmvd on oil fuel. GE developed multi-nozzle quiet combustors (MNQC) for the MS7001EA and MS7001FA capable of achieving 25 ppmvd on gas fuel and 42 ppmvd on oil, using either water or steam injection. Since October 1987, more than 26 MNQC-equipped MS7001s that use water or steam injection have been placed in service. One unit that uses steam injection has operated nearly 50,000 hours at 25 ppmvd $NO_x$(at 15% $O_2$).

Frequent combustion inspections and decreased hardware life are undesirable side effects that can result from the use of diluent injection to reduce $NO_x$ emissions from combustion turbines. For applications that require $NO_x$ emissions below 42 ppmvd (or 25 ppmvd in the case of the MS7001EA or MS7001FA MNQC), or to avoid the significant cycle efficiency penalties incurred when water or steam injection is used for $NO_x$ control, one of the other two principal

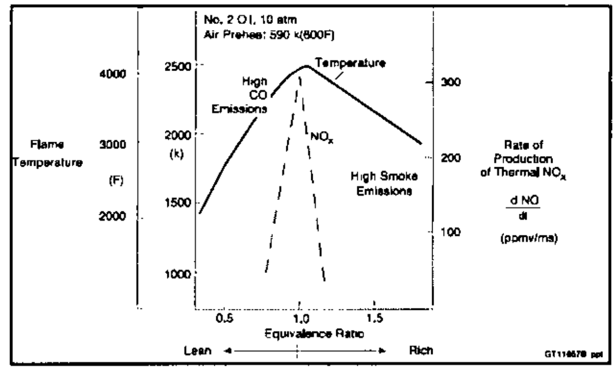


**Figure A3. Rate of thermal Nox production**

methods of $NO_x$ control mentioned above must be used.

Selective catalytic reduction (SCR) converts NO and $NO_2$ in the gas turbine exhaust stream to molecular nitrogen and oxygen by reacting the $NO_x$ with ammonia in the presence of a catalyst. Conventional SCR technology requires that the temperature of the exhaust stream remain in a narrow range (550 F to 750 F or 288 C to 399 C) and is restricted to applications with a heat recovery system installed in the exhaust. The SCR is installed at a location in the boiler where the exhaust gas temperature has decreased to the above temperature range. New high-temperature SCR technology is being developed that may allow SCRs to be used for applications without heat recovery boilers.

For an MS7001EA gas turbine, an SCR designed to remove 90% of the $NO_x$ from the gas turbine exhaust stream has a volume of approximately 175 cubic meters and weighs 111 tons. It is comprised of

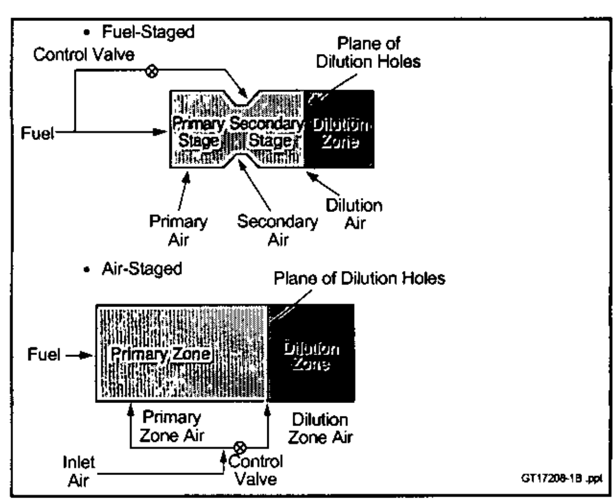


**Figure A4. Staged combustors**

segments stacked in the exhaust duct. Each segment has a honeycomb pattern with passages that are aligned in the direction of the exhaust gas flow. A catalyst, such as vanadium pentoxide, is deposited on the surface of the honeycomb.

SCR systems are sensitive to fuels containing more than 1,000 ppm of sulfur (light distillate oils may have up to 0.8% sulfur). There are two reasons for this sensitivity: first, sulfur poisons the catalyst being used in SCRs.

Secondly, the ammonia will react with sulfur in the presence of the catalyst to form ammonium bisulfate, which is extremely corrosive, particularly near the discharge of a heat recovery boiler. Special catalyst materials that are less sensitive to sulfur have been identified, and there are some theories as to how to inhibit the formation of ammonium bisulfate. This, however, remains an open issue with SCRs.

More than 100 GE units have accumulated more than 100,000 operating hours with SCRs installed. Twenty of the units are in Japan; others are located in California, New Jersey, New York and several other eastern U.S. states. Units operating with SCRs include MS9000s, MS7000s, MS6000s, LM2500s and LM5000s.

Lean premixed combustion is the basis for achieving low emissions from Dry Low $NO_x$ and catalytic combustors. GE has participated in the development of catalytic combustors for many years. These systems use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. They have the potential to achieve extremely low emissions levels without resorting to exhaust gas cleanup. Technical challenges in the combustor and in the catalyst and reactor bed materials must be overcome in order to develop an operational catalytic combustor. GE has development programs in place with both ceramic and catalyst manufacturers to address these challenges. GE does not believe commercial systems employing this technology will be available in the near term.

# REFERENCES


1. Washam, R. M., "Dry Low $NO_x$ Combustion System for Utility Gas Turbine," ASME Paper 83-JPGC-GT-13, Sept. 1983.
2. Davis, L. B. and Washam, R. M., "Development of a Dry Low $NO_x$ Combustor," ASME Paper No. 89-GT-255, June 1989.
3. Dibelius, N.R., Hilt, M.B., and Johnson, R.H., "Reduction of Nitrogen Oxides from Gas Turbines by Steam Injection," ASME Paper No. 71-GT-58, Dec. 1970
4. Miller, H. E., "Development of the Quiet Combustor and Other Design Changes to Benefit Air Quality," American Cogeneration Association, San Francisco, March 1988.
5. Cutrone, M. B., Hilt, M. B., Goyal, A., Ekstedt, E. E., and Notardonato, J., "Evaluation of Advanced Combustor for Dry $NO_x$ Suppression with Nitrogen Bearing Fuels in Utility and Industrial Gas Turbines," ASME Paper 81-GT-125, March 1981.
6. Zeldovich, J., "The Oxidation of Nitrogen in Combustion and Explosions," Acta Physicochimica USSR, Vol. 21, No. 4, 1946, pp 577-628.
7. Washam, R. M., "Dry Low $NO_x$ Combustion System for Utility Gas Turbine," ASME Paper 83-JPGC-GT-13, Sept. 1983.
8. Davis, L. B., and Washam, R. M., "Development of a Dry Low $NO_x$ Combustor," ASME Paper No. 89-GT-255, June 1989.


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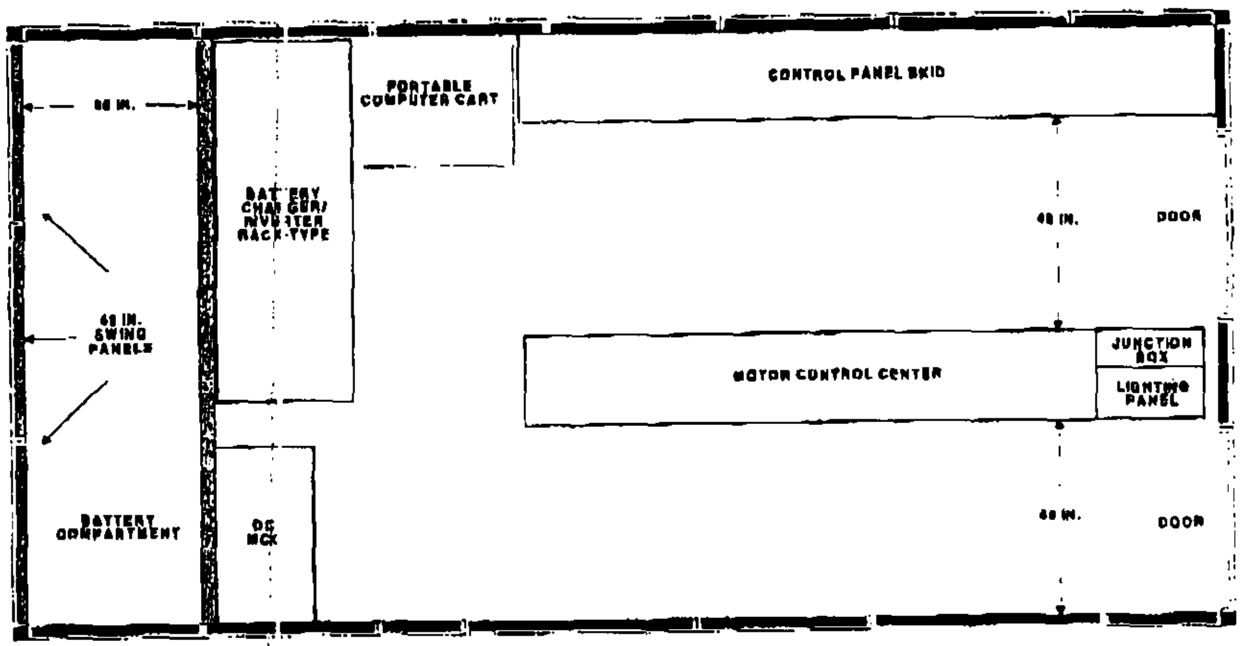
## LIST OF FIGURES

# ATTACHMENT II

# GE MARK V CONTROL SYSTEM TECHNICAL LITERATURE

common skid and located in the PEECC. The customer control local interface <I> is also located in the PEECC. In addition to the control systems, the PEECC also houses the gas turbine motor control centers and batteries, rack and charger (s). The arrangement of the equipment is shown in the typical compartment layout below.

**Packaged Electronic and Electrical Control Compartment (PEECC)**
(Typical)




## 3.4.2 Gas Turbine Control System

The SPEEDTRONIC™ Mark V gas turbine control system is a state-of-the-art Triple Modular Redundant (TMR) microprocessor control system. The core of this system is the three separate but identical controllers called <R>, <S>, and <T>. All critical control algorithms, protective functions, and sequencing are performed by these processors. In so doing, they also acquire the data needed to generate outputs to the turbine. Protective outputs are routed through the <P> protective module consisting of triple redundant

™ A Trademark of the General Electric Company processors <X>, <Y>, and <Z>, which also provide independent protection for certain critical functions such as overspeed.

The three control processors, <R>, <S>, and <T>, acquire data from triple-redundant sensors as well as from dual or single sensors. All critical sensors for continuous controls, as well as protection, are triple-redundant. Other sensors are dual or single devices fanned out to all three control processors. The extremely high reliability achieved by TMR control systems is due in considerable measure to the use of triple sensors for all critical parameters.

### 3.4.2.1 Electronics

All of the microprocessor-based controls have a modular design for ease of maintenance. Each module or controller contains up to five cards, including a power supply. Multiple microprocessors reside in each controller which distribute the processing for maximum performance. Individual microprocessors are dedicated to specific I/O assignments, application software communications, etc., and the processing is performed in a real-time, multi-tasking operating system. Communications between the controller's five cards is accomplished with ribbon cables and gas-tight connectors. Communication between individual controllers is performed on high-speed Arcnet links.

### 3.4.2.2 Shared Voting

Software Implemented Fault Tolerance (SIFT) and hardware voting are utilized by the SPEEDTRONIC Mark V TMR control system. At the beginning of each computing time frame, each controller independently reads its sensors and exchanges this data with the data from the other two controllers. The median value of each analog input is calculated in each controller and then used as the resultant control parameter for that controller. Diagnostic algorithms monitor a predefined deadband for each analog input to each controller, and if one of the analog inputs deviates from this deadband, a diagnostic alarm is initiated to advise maintenance personnel.

Contact inputs are voted in a similar manner. Each contact input connects to a single terminal point and is parallel wired to three contact input cards. Each card optically isolates the 125 or 24 V dc input, and then a dedicated 80196 processor in each card time stamps the input to within 1 ms resolution. These signals are then transmitted to the <R>, <S>, and <T> controllers for voting and execution of the application software. This technique eliminates any single point failure in the software voting system. Redundant contact inputs for certain functions such as low lube oil pressure are connected to three separate terminal points and then individually voted. With this SIFT technique, multiple failures of contact or analog inputs can be accepted by the control system without causing an erroneous trip command from any of the three controllers as long as the failures are not from the same circuit.

Another form of voting is accomplished through hardware voting of analog outputs. Three coil servos on the valve actuators are separately driven from each controller, and the position feedback is provided by three LVDTs. The normal position of each valve is the average of the three commands from <R>, <S>, and <T>. The resultant averaging circuit has sufficient gain to override a gross failure of any controller, such as a controller output being driven to saturation. Diagnostics monitor the servo coil currents and the D/A converters in addition to the LVDTs.

### 3.4.2.3 PC Based Operator Interface

The operator interface, <I>, consists of a PC, color monitor, cursor positioning device, keyboard, and printer. The keyboard is primarily used for maintenance such as editing application software or alarm messages. While the keyboard is not necessary, it is convenient for accessing displays with dedicated function keys and adjusting setpoints by entering a numeric value rather than issuing a manual raise/lower command. Setpoint and logic commands require an initial selection which is followed by a confirming execute command.

The operator interface can be used as the sole interface or as a local maintenance work station with all operator control and monitoring coming from communication links with a plant distributed control system (DCS).

### 3.4.2.4 Direct Sensor Interface

Input/output (I/O) is designed for direct interface to turbine and generator devices such as thermocouples, RTDs and vibration sensors, flame sensors, and proximity probes. Direct monitoring of these sensors eliminates the cost and potential reliability factors associated with interposing transducers and instrumentation. All of the resultant data is visible to the operator from the SPEEDTRONIC Mark V operator interface.

In addition, the communication link enables the resultant data to be visible from a plant Distributed Control System (DCS) system.

3.4.2.5 **Built-in Diagnostics**

The control system has extensive built-in diagnostics and includes "power-up", background and manually initiated diagnostic routines capable of identifying both control panel, sensor, and output device faults. These faults are identified down to the board level for the panel, and to the circuit level for the sensor or actuator component. On-line replacement of boards is made possible by the triply redundant design and is also available for those sensors where physical access and system isolation are feasible.

3.4.2.6 **Generator Interface and Control**

The primary point of control for the generator is though the operator interface. However, the control system is integrated with the EX2000BR brushless excitation system over an Arcnet local area network (LAN). The SPEEDTRONIC Mark V is used to control megawatt output and the EX2000BR is used to control megavar output. The generator control panel is used to provide primary protection for the generator. This protection is further augmented by protection features located in the EX2000BR and the SPEEDTRONIC Mark V.

3.4.2.7 **Synchronizing Control and Monitoring**

Automatic synchronization is performed by the <X>, <Y>, and <Z> cards in conjunction with the <R>, <S>, and <T> controllers. The controllers match speed and voltage and issue a command to close the breaker based on a predefined breaker closure time. Diagnostics monitor the actual breaker closure time and self-correct each command.

Another feature of the system is the ability to synchronize manually via the operator interface instead of using the traditional synchroscope on the generator protective panel. Operators can choose one additional mode of operation by selecting the monitor mode, which automatically matches speed and voltage, but waits for the operator to review all pertinent data on the CRT display before issuing a breaker close command.

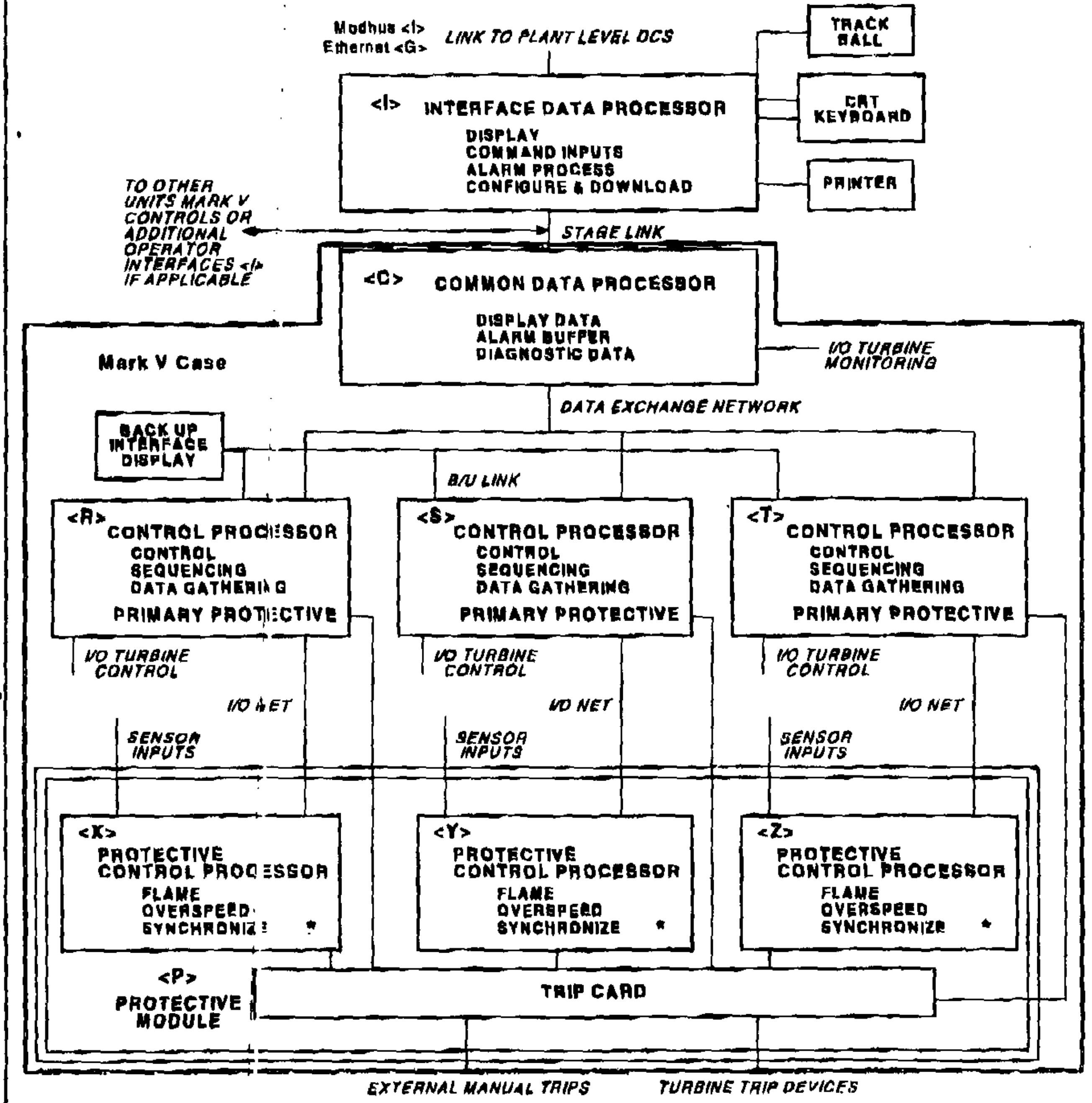
### 3.4.2.8 Architecture

The SPEEDTRONIC Mark V control configuration diagram depicts several advantages for increased reliability and ease of interface. For example:

- Multiple unit control from a single <I>
- Back-up display wired directly to <R>, <S>, and <T> controllers
- PC interface to plant DCS system
- Hard wire protective signal from <R> <S> <T> controllers
- Additional protective processors <X>, <Y>, <Z>

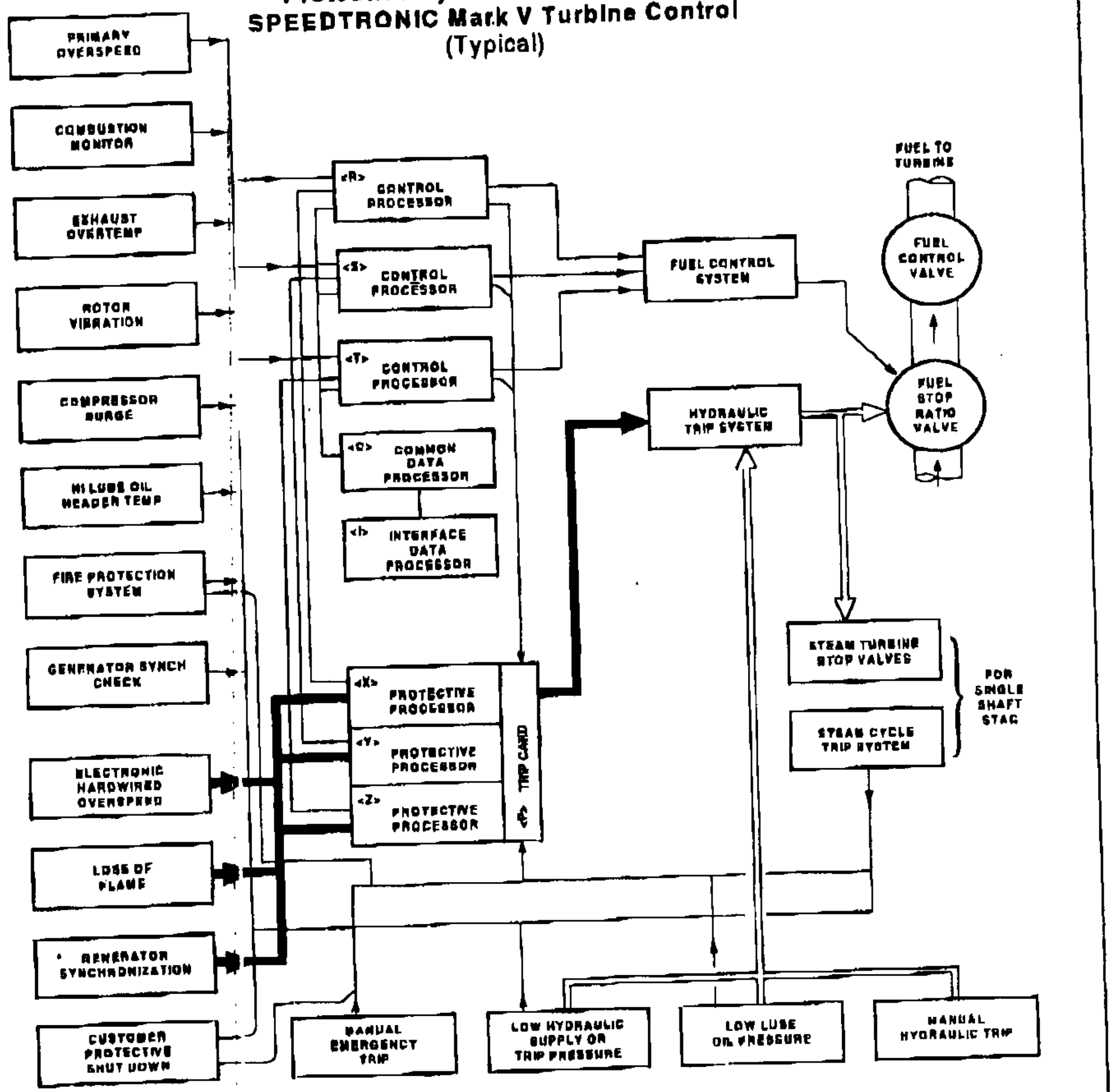
The protective block diagram shows the built in redundancy/reliability of the SPEEDTRONIC Mark V control system. For example, if there is an overspeed condition requiring a trip of the unit, the first line of defense would be the primary overspeed protection via the <R>, <S>, and <T> controllers. All three trip signals then pass to the <P>protective module trip card where two out of three voting occurs prior to sending the automatic fuel supply trip signal. The secondary overspeed protection is via the <X>, <Y>, and <Z> protective control processor cards which similarly send their independent trip signals to the <P>protective module trip card for voting.

**Standard SPEEDTRONIC Mark V Control Configuration**
**(Typical)**




* Generator Drive Applications Only

## Protective System Block Diagram
## SPEEDTRONIC Mark V Turbine Control
(Typical)




* Generator Drive Applications Only

cntrls 103

# ATTACHMENT III

# GE EMISSIONS GUARANTEE

GE Power Systems
Global Power Plant Systems
General Electric Company
One River Road, Schenectady, NY 12345
518-385-0683

July 22, 1999

Eric Booth
Enron Engineering & Construction Company
333 Clay Street, Suite 400
Houston, TX 77002-7361

Subject: TECO Power Services
Emissions Guarantees

Dear Eric:

The General Electric dual fuel fired PG7121 EA Combustion Gas Turbine, purchased for TECO Power Services Hardee Power Station CT-2B has guaranteed emissions of NOx at 9 ppm (@15% O2) and CO at 25 ppm while operating on natural gas fuel, between 65 and 100%load, corrected to 59°F and 60% relative humidity. It is expected that the gas turbine will not exceed these emission levels over the life of the unit, as long as GE's maintenance practices are followed.

In addition, there have been at least seven 7EA gas turbines with DLN-1, Dual Fuel combustion systems, that have proven to meet guarantees of 9 PPM NOx and 25 PPM CO in the last five years.

Sincerely,

Jeff Darst
Project Manager

cc: W Turnipseed, NEPCO
DW Ross, TECO Power Services
TECO002

# ATTACHMENT IV

# GE 7EA CT STACK TEST RESULTS

# ENTROPY, INC.

Specialists in Air Emissions Technology

*P.O. Box 12291 • Research Triangle Park, North Carolina 27709-2291*
*(919) 781-3550 • (800) 486-3550 • Fax (919) 787-8442*

**VOLUME 1**

**TEXT AND APPENDIX A**

**PERFORMANCE AND COMPLIANCE TESTING**

**REFERENCE NO. 15533**

**PANDA-BRANDYWINE COGENERATION FACILITY**

**BRANDYWINE, MARYLAND**

**EMISSIONS TESTING FOR:**
**CARBON MONOXIDE**
**NITROGEN OXIDES**
**PARTICULATE**
**SULFUR DIOXIDE**
**SULFURIC ACID MIST**
**TOTAL HYDROCARBONS**

RAYTHEON ENGINEERS & CONSTRUCTORS
PO NO SCT 96.05 PROJECT NO 8346001
REQN OR TASK SCT 96.05 RECEIVED 11/06/96
TAG NO FILE NO 2
☒ FOR INITIAL REVIEW ☐ FOR REVIEW OF REVISION
☐ W/COMMENT-RELEASED FOR FAB WITH COMMENT INCORP. FINAL REQUIRED
☐ NO COMMENT-RELEASED FOR FAB-FINAL REQUIRED
☐ NOT RELEASED FOR FAB - REVISE & RESUBMIT FOR REVIEW
☒ FINAL-NO RETURN REQ'D ☐ FOR INFO-NO RETURN REQ'D
BY RDH DATE 11-6-96
REVIEW DOES NOT RELIEVE SELLER FROM RESPONSIBILITY FOR COMPLIANCE WITH THE CONTRACT DOCUMENTS.

**UNIT NOS. 1 AND 2**

**PERFORMED FOR: RAYTHEON ENGINEERS AND CONSTRUCTORS**

**SEPTEMBER AND OCTOBER 1996**

**REPORT CERTIFICATION**

**EI Reference Number 15533**

The sampling and analysis performed for this report were carried out under my direction and supervision, and I hereby certify that, to the best of my knowledge, the test report is authentic and accurate.

Signature: William H Harris

Date: 11/5/96

William H. Harris
Project Director
Client Services Division

Table of Contents

## VOLUME 1

Table of Contents (continued)

## List of Tables and Figures

# TABLE 1-2
# TEST LOG
# UNIT NO. 1 STACK - NO. 2 FUEL OIL
# OCTOBER 1996

| Test Condition | Sampling Objective | Test Method | Test Date | Run Numbers | Flue Gas Composition | Volumetric Air Flow Rate |
|---|---|---|---|---|---|---|
| **PERFORMANCE TESTS** | | | | | | |
| **No. 2 Fuel Oil** | $O_2/CO_2$, $SO_2$, $NO_x$, CO, & THC | EPA 3A, 6C, 7E, 10, & 25A | 10/09<br>10/09<br>10/09 | 1-O-CEM-1<br>1-O-CEM-2<br>1-O-CEM-3 | 1-O-CEM-1<br>1-O-CEM-2<br>1-O-CEM-3 | 1-O-M5/8-1<br>1-O-M5/8-2<br>1-O-M5/8-3 |
| | Particulate, $SO_2$, $SO_3$, & $H_2SO_4$ | EPA 5 & 8 | 10/09<br>10/09<br>10/09 | 1-O-M5/8-1<br>1-O-M5/8-2<br>1-O-M5/8-3 | 1-O-CEM-1<br>1-O-CEM-2<br>1-O-CEM-3 | NA |
| **COMPLIANCE TESTS** | | | | | | |
| **No. 2 Fuel Oil 100% Load** | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/09<br>10/09<br>10/09 | 1-O-100-1<br>1-O-100-2<br>1-O-100-3 | 1-O-100-1<br>1-O-100-2<br>1-O-100-3 | Fuel Analysis & Process Data |
| **No. 2 Fuel Oil 75% Load** | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/09<br>10/09<br>10/09 | 1-O-75-1<br>1-O-75-2<br>1-O-75-3 | 1-O-75-1<br>1-O-75-2<br>1-O-75-3 | Fuel Analysis & Process Data |
| **No. 2 Fuel Oil 50% Load** | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/09<br>10/09<br>10/09 | 1-O-50-1<br>1-O-50-2<br>1-O-50-3 | 1-O-50-1<br>1-O-50-2<br>1-O-50-3 | Fuel Analysis & Process Data |
| **No. 2 Fuel Oil 30% Load** | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/09<br>10/09<br>10/09 | 1-O-30-1<br>1-O-30-2<br>1-O-30-3 | 1-O-30-1<br>1-O-30-2<br>1-O-30-3 | Fuel Analysis & Process Data |

**TABLE 1-3**
**TEST LOG**
**UNIT NO. 2 STACK - NATURAL GAS**
**SEPTEMBER 1996**

| Test Condition | Sampling Objective | Test Method | Test Date | Run Numbers | Flue Gas Composition | Volumetric Air Flow Rate |
|---|---|---|---|---|---|---|
| **PERFORMANCE TESTS** | | | | | | |
| Natural Gas | $O_2/CO_2$, $SO_2$, $NO_x$, CO, & THC | EPA 3A, 6C, 7E, 10, & 25A | 9/25<br>9/25<br>9/25 | 2-NG-CEM-1<br>2-NG-CEM-2<br>2-NG-CEM-3 | 2-NG-CEM-1<br>2-NG-CEM-2<br>2-NG-CEM-3 | 2-NG-M5/8-1<br>2-NG-M5/8-2<br>2-NG-M5/8-3 |
| | Particulate, $SO_2$, $SO_3$, & $H_2SO_4$ | EPA 5 & 8 | 9/25<br>9/25<br>9/25 | 2-NG-M5/8-1<br>2-NG-M5/8-2<br>2-NG-M5/8-3 | 2-NG-CEM-1<br>2-NG-CEM-2<br>2-NG-CEM-3 | NA |
| **COMPLIANCE TESTS** | | | | | | |
| Natural Gas 30% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 9/27<br>9/27<br>9/27 | 2-NG-30-1<br>2-NG-30-2<br>2-NG-30-3 | 2-NG-30-1<br>2-NG-30-2<br>2-NG-30-3 | Fuel Analysis & Process Data |
| Natural Gas 50% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 9/27<br>9/27<br>9/27 | 2-NG-50-1<br>2-NG-50-2<br>2-NG-50-3 | 2-NG-30-1<br>2-NG-30-2<br>2-NG-30-3 | Fuel Analysis & Process Data |
| Natural Gas 75% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 9/27<br>9/27<br>9/27 | 2-NG-75-1<br>2-NG-75-2<br>2-NG-75-3 | 2-NG-30-1<br>2-NG-30-2<br>2-NG-30-3 | Fuel Analysis & Process Data |
| Natural Gas 100% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 9/27<br>9/27<br>9/27 | 2-NG-100-1<br>2-NG-100-2<br>2-NG-100-3 | 2-NG-30-1<br>2-NG-30-2<br>2-NG-30-3 | Fuel Analysis & Process Data |

**TABLE 1-4**
**TEST LOG**
**UNIT NO. 2 STACK - NO. 2 FUEL OIL**
**OCTOBER 1996**

| Test Condition | Sampling Objective | Test Method | Test Date | Run Numbers | Flue Gas Composition | Volumetric Air Flow Rate |
|---|---|---|---|---|---|---|
| PERFORMANCE TESTS | | | | | | |
| No. 2 Fuel Oil | $O_2/CO_2$, $SO_2$, $NO_x$, CO, & THC | EPA 3A, 6C, 7E, 10, & 25A | 10/10<br>10/10<br>10/10 | 2-O-CEM-1<br>2-O-CEM-2<br>2-O-CEM-3 | 2-O-CEM-1<br>2-O-CEM-2<br>2-O-CEM-3 | 2-O-M5/8-1<br>2-O-M5/8-2<br>2-O-M5/8-3 |
| | Particulate, $SO_2$, $SO_3$, & $H_2SO_4$ | EPA 5 & 8 | 10/10<br>10/10<br>10/10 | 2-O-M5/8-1<br>2-O-M5/8-2<br>2-O-M5/8-3 | 2-O-CEM-1<br>2-O-CEM-2<br>2-O-CEM-3 | NA |
| COMPLIANCE TESTS | | | | | | |
| No. 2 Fuel Oil 30% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/14<br>10/14<br>10/14 | 2-O-30-1<br>2-O-30-2<br>2-O-30-3 | 2-O-30-1<br>2-O-30-2<br>2-O-30-3 | Fuel Analysis & Process Data |
| No. 2 Fuel Oil 50% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/14<br>10/14<br>10/14 | 2-O-50-1<br>2-O-50-2<br>2-O-50-3 | 2-O-50-1<br>2-O-50-2<br>2-O-50-3 | Fuel Analysis & Process Data |
| No. 2 Fuel Oil 75% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/14<br>10/14<br>10/14 | 2-O-75-1<br>2-O-75-2<br>2-O-75-3 | 2-O-75-1<br>2-O-75-2<br>2-O-75-3 | Fuel Analysis & Process Data |
| No. 2 Fuel Oil 100% Load | $O_2/CO_2$ & $NO_x$ | EPA 20 | 10/10<br>10/10<br>10/10 | 2-O-100-1<br>2-O-100-2<br>2-O-100-3 | 2-O-100-1<br>2-O-100-2<br>2-O-100-3 | Fuel Analysis & Process Data |

**TABLE 1-5**
**TEST PARTICIPANTS**
**UNIT NOS. 1 AND 2**
**SEPTEMBER AND OCTOBER 1996**

| | |
|---|---|
| **Raytheon Engineers and Constructors** | Jeff Jacobsohn<br>Test Coordinator |
| | Al Vaught<br>Test Observer |
| **Entropy, Inc.** | William H. Harris<br>Project Director |
| | Julie R. Ruff<br>Project Manager |
| | James E. Daley<br>Sampling Team Leader |
| | Michael S. Riedel<br>Sampling Team Leader |
| | Danny L. Speer<br>Sampling Team Leader |

## 2.0 SUMMARY OF RESULTS

### 2.1 Presentation

**Tables 2-1** and **2-2** present the performance test results versus the permitted limits for Unit No. 1 and Unit No. 2, respectively. The compliance test results for Unit No. 1 are presented in **Tables 2-3** and **2-4** and Unit No. 2 compliance test results are presented in **Tables 2-5** and **2-6**. Detailed test results are presented in Volume 1, **Appendix A**; field data is given in Volume 2, **Appendix B**; and analytical data can be found in Volume 2, **Appendix C**.

### 2.2 Cyclonic Flow Checks

A cyclonic flow check was performed at each sampling location to determine if any cyclonic flow existed. Average yaw angles of < 3 ° were measured, indicating acceptable locations with respect to EPA Method 1 requirements.

### 2.3 Compliance (EPA Method 20) Tests

Each combustion turbine was tested according to the requirements of Subpart GG of 40 CFR, Part 60. These requirements included the determination of exhaust gas $NO_x$ concentrations (ppm $NO_x$ corrected for dilution to 15% $O_2$) and in terms of pounds $NO_x$ (as $NO_2$) per hour at four load conditions. To measure the $NO_x$ emissions on a pound per hour basis, average exhaust gas flow rates were calculated for each run using EPA Method 19 and fuel flow rate and heat content information.

The correction of $NO_x$ concentration to ISO standard ambient conditions (59 °F temperature, 0.00633 g $H_2O$/g air absolute humidity) prescribed under Subpart GG was not applied, since these parameters are accounted for in the $NO_x$ control water injection algorithm. The Speedtronic Mark V control system automatically adjusts water injection rates, based on current ambient conditions and operating load, to limit $NO_x$ concentrations to levels expected when operating at the current load under ISO standard conditions. Further correction to ISO conditions would have been redundant.

**TABLE 2-1**
**PERFORMANCE TEST RESULTS VERSUS PERMITTED LIMITS**
**UNIT NO. 1 STACK**
**SEPTEMBER AND OCTOBER 1996**

| | Rep 1 | Rep 2 | Rep 3 | Average | Permit Limit |
|---|---|---|---|---|---|
| **NATURAL GAS** | | | | | |
| **Concentration, ppmvd @ 15% $O_2$** | | | | | |
| Nitrogen Oxides as $NO_2$ | 7.2 | 7.9 | 7.7 | 7.6 | 9 |
| **Emission Rate, lb/hr** | | | | | |
| Carbon Monoxide | 23.3 | 19.8 | 16.6 | 19.9 | 59.00 |
| Nitrogen Oxides as $NO_2$ | 28.1 | 29.8 | 28.9 | 28.9 | 35.0 |
| Particulate | 2.79 | 0.666 | 2.45 | 1.97 | 7.0 |
| Sulfur Dioxide (EPA 5/8) | 20.0 | 23.0 | 17.8 | 20.3 | 29.0 |
| Sulfur Dioxide (EPA 6C) | 0.5 | 0.5 | 0.0 | 0.3 | 29.0 |
| Sulfuric Acid Mist | 1.87 | 1.16 | 2.71 | 1.91 | 3.0 |
| Total Hydrocarbons as C | 0.22 | 1.19 | 1.07 | 0.83 | 2.0 |
| **NO. 2 FUEL OIL** | | | | | |
| **Concentration, ppmvd @ 15% $O_2$** | | | | | |
| Nitrogen Oxides as $NO_2$ | 47.9 | 40.2 | 40.2 | 42.8 | 54 |
| **Emission Rate, lb/hr** | | | | | |
| Carbon Monoxide | 0.0 | 0.0 | 0.5 | 0.2 | 71.0 |
| Nitrogen Oxides as $NO_2$ | 194.6 | 168.0 | 163.9 | 175.5 | 239.0 |
| Particulate | 3.06 | 3.68 | 9.90 | 5.55 | 15.0 |
| Sulfur Dioxide (EPA 5/8) | 31.0 | 33.2 | 33.1 | 32.4 | 54.0 |
| Sulfur Dioxide (EPA 6C) | 25.2 | 29.9 | 28.6 | 27.9 | 54.0 |
| Sulfuric Acid Mist | 3.83 | 4.47 | 4.55 | 4.28 | 6.0 |
| Total Hydrocarbons as C | 1.78 | 1.57 | 1.11 | 1.49 | 5.00 |

**TABLE 2-2**
**PERFORMANCE TEST RESULTS VERSUS PERMITTED LIMITS**
**UNIT NO. 2 STACK**
**SEPTEMBER AND OCTOBER 1996**

| | Rep 1 | Rep 2 | Rep 3 | Average | Permit Limit |
|---|---|---|---|---|---|
| **NATURAL GAS** | | | | | |
| **Concentration, ppmvd @ 15% $O_2$** | | | | | |
| Nitrogen Oxides as $NO_2$ | 8.8 | 8.3 | 8.8 | 8.6 | 9 |
| **Emission Rate, lb/hr** | | | | | |
| Carbon Monoxide | 14.3 | 14.3 | 15.1 | 14.6 | 59.00 |
| Nitrogen Oxides as $NO_2$ | 32.2 | 30.1 | 32.6 | 31.6 | 35.0 |
| Particulate | 2.67 | 3.99 | 1.33 | 2.66 | 7.0 |
| Sulfur Dioxide (EPA 5/8) | 16.5 | 23.2 | 21.0 | 20.2 | 29.0 |
| Sulfur Dioxide (EPA 6C) | 0.0 | 0.0 | 1.1 | 0.37 | 29.0 |
| Sulfuric Acid Mist | 2.38 | 1.91 | 3.72 | 2.67 | 3.0 |
| Total Hydrocarbons as C | 0.22 | 1.07 | 0.66 | 0.65 | 2.0 |
| **NO. 2 FUEL OIL** | | | | | |
| **Concentration, ppmvd @ 15% $O_2$** | | | | | |
| Nitrogen Oxides as $NO_2$ | 46.3 | 46.6 | 45.0 | 46.0 | 54 |
| **Emission Rate, lb/hr** | | | | | |
| Carbon Monoxide | 0.7 | 0.0 | 0.0 | 0.2 | 71.0 |
| Nitrogen Oxides as $NO_2$ | 182.2 | 192.0 | 192.5 | 188.9 | 239.0 |
| Particulate | 0.932 | 6.88 | 5.42 | 4.41 | 15.0 |
| Sulfur Dioxide (EPA 5/8) | 32.0 | 33.4 | 34.6 | 33.3 | 54.0 |
| Sulfur Dioxide (EPA 6C) | 8.6 | 12.7 | 16.3 | 12.5 | 54.0 |
| Sulfuric Acid Mist | 3.11 | 3.61 | 3.30 | 3.34 | 6.0 |
| Total Hydrocarbons as C | 1.08 | 1.27 | 1.17 | 1.17 | 5.00 |

**TABLE 2-3**
**COMPLIANCE TEST RESULTS**
**UNIT NO. 1 STACK - NATURAL GAS**
**SEPTEMBER 1996**

| Natural Gas | Rep 1 | Rep 2 | Rep 3 | Average | Permit Limit |
|---|---|---|---|---|---|
| **100% LOAD (9/26/96)** | | | | | |
| Sample Time | 1815 - 1831 | 1848 - 1904 | 1912 - 1928 | | - - |
| Load, MW | 77.28 | 77.28 | 77.27 | 77.28 | - - |
| ppmvd $NO_x$ | 6.7 | 6.9 | 7.0 | 6.9 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 6.8 | 7.0 | 7.1 | 7.0 | 9 |
| Flow Rate, dscfh | 2.89 E+07 | 2.89 E+07 | 2.89 E+07 | 2.89 E+07 | - - |
| lb $NO_x$/hr | 23.04 | 23.62 | 24.12 | 23.59 | 35.0 |
| **75% LOAD (9/26/96)** | | | | | |
| Sample Time | 1943 - 1959 | 2007 - 2023 | 2031 - 2047 | | - - |
| Load, MW | 69.95 | 70.09 | 70.20 | 70.08 | - - |
| ppmvd $NO_x$ | 7.5 | 7.4 | 7.4 | 7.4 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 7.4 | 7.3 | 7.3 | 7.3 | 9 |
| Flow Rate, dscfh | 2.59 E+07 | 2.60 E+07 | 2.59 E+07 | 2.59 E+07 | - - |
| lb $NO_x$/hr | 23.06 | 22.92 | 22.78 | 22.92 | 35.0 |
| **50% LOAD (9/27/96)** | | | | | |
| Sample Time | 0730 - 0746 | 0754 - 0810 | 0818 - 0834 | | - - |
| Load, MW | 65.57 | 65.45 | 64.96 | 65.33 | - - |
| ppmvd $NO_x$ | 7.7 | 7.5 | 7.4 | 7.5 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 7.8 | 7.6 | 7.5 | 7.6 | 9 |
| Flow Rate, dscfh | 2.56 E+07 | 2.52 E+07 | 2.50 E+07 | 2.53 E+07 | - - |
| lb $NO_x$/hr | 23.39 | 22.49 | 22.09 | 22.66 | 35.0 |
| **30% LOAD (9/27/96)** | | | | | |
| Sample Time | 0850 - 0906 | 0914 - 0930 | 0938 - 0954 | | - - |
| Load, MW | 60.29 | 59.96 | 60.21 | 60.15 | - - |
| ppmvd $NO_x$ | 7.7 | 7.9 | 7.7 | 7.8 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 7.7 | 7.8 | 7.7 | 7.7 | 9 |
| Flow Rate, dscfh | 2.34 E+07 | 2.34 E+07 | 2.34 E+07 | 2.34 E+07 | - - |
| lb $NO_x$/hr | 21.62 | 21.94 | 21.46 | 21.67 | 35.0 |

**TABLE 2-4**
**COMPLIANCE TEST RESULTS**
**UNIT NO. 1 STACK - NO. 2 FUEL OIL**
**OCTOBER 1996**

| No. 2 Fuel Oil | Rep 1 | Rep 2 | Rep 3 | Average | Permit Limit |
|---|---|---|---|---|---|
| **100% LOAD (10/09/96)** | | | | | |
| Sample Time | 0830 - 0846 | 1120 - 1136 | 1400 - 1416 | | - - |
| Load, MW | 79.35 | 77.87 | 76.56 | 77.93 | - - |
| ppmvd $NO_x$ | 50.5 | 43.3 | 41.2 | 45.0 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 48.5 | 40.6 | 38.1 | 42.4 | 54 |
| Flow Rate, dscfh | 2.97 E+07 | 2.95 E+07 | 2.84 E+07 | 2.92 E+07 | - - |
| lb $NO_x$/hr | 179.12 | 152.45 | 139.37 | 156.98 | 239.0 |
| **75% LOAD (10/09/96)** | | | | | |
| Sample Time | 1611 - 1627 | 1633 - 1649 | 1655 - 1711 | | - - |
| Load, MW | 70.01 | 70.06 | 70.18 | 70.08 | - - |
| ppmvd $NO_x$ | 43.6 | 44.5 | 44.3 | 44.1 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 40.8 | 41.4 | 41.0 | 41.1 | 54 |
| Flow Rate, dscfh | 2.61 E+07 | 2.61 E+07 | 2.61 E+07 | 2.61 E+07 | - - |
| lb $NO_x$/hr | 136.18 | 138.72 | 137.71 | 137.54 | 239.0 |
| **50% LOAD (10/09/96)** | | | | | |
| Sample Time | 1726 - 1742 | 1750 - 1812 | 1818 - 1834 | | - - |
| Load, MW | 64.94 | 65.25 | 65.23 | 65.14 | - - |
| ppmvd $NO_x$ | 44.9 | 44.5 | 43.4 | 44.3 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 41.9 | 41.7 | 40.6 | 41.4 | 54 |
| Flow Rate, dscfh | 2.46 E+07 | 2.44 E+07 | 2.47 E+07 | 2.46 E+07 | - - |
| lb $NO_x$/hr | 132.04 | 129.80 | 127.70 | 129.85 | 239.0 |
| **30% LOAD (10/09/96)** | | | | | |
| Sample Time | 1844 - 1900 | 1906 - 1922 | 1928 - 1944 | | - - |
| Load, MW | 60.37 | 60.22 | 60.27 | 60.29 | - - |
| ppmvd $NO_x$ | 43.9 | 43.3 | 42.7 | 43.3 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 41.9 | 41.4 | 40.9 | 41.4 | 54 |
| Flow Rate, dscfh | 2.34 E+07 | 2.35 E+07 | 2.35 E+07 | 2.35 E+07 | - - |
| lb $NO_x$/hr | 122.70 | 121.21 | 119.84 | 121.25 | 239.0 |

**TABLE 2-5**
**COMPLIANCE TEST RESULTS**
**UNIT NO. 2 STACK - NATURAL GAS**
**SEPTEMBER 1996**

| Natural Gas | Rep 1 | Rep 2 | Rep 3 | Average | Permit Limit |
|---|---|---|---|---|---|
| **100% LOAD (9/27/96)** | | | | | |
| Sample Time | 1057 - 1113 | 1121 - 1137 | 1145 - 1201 | | - - |
| Load, MW | 75.91 | 75.80 | 75.41 | 75.71 | - - |
| ppmvd $NO_x$ | 8.9 | 8.8 | 8.9 | 8.9 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 8.7 | 8.6 | 8.7 | 8.7 | 9 |
| Flow Rate, dscfh | 2.66 E+07 | 2.66 E+07 | 2.65 E+07 | 2.66 E+07 | - - |
| lb $NO_x$/hr | 28.10 | 27.98 | 27.96 | 28.01 | 35.0 |
| **75% LOAD (9/27/96)** | | | | | |
| Sample Time | 1215 - 1231 | 1239 - 1255 | 1303 - 1319 | | - - |
| Load, MW | 70.25 | 70.07 | 70.19 | 70.17 | - - |
| ppmvd $NO_x$ | 5.9 | 5.7 | 5.9 | 5.8 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 5.9 | 5.8 | 6.1 | 5.9 | 9 |
| Flow Rate, dscfh | 2.56 E+07 | 2.56 E+07 | 2.55 E+07 | 2.56 E+07 | - - |
| lb $NO_x$/hr | 17.89 | 17.52 | 17.93 | 17.78 | 35.0 |
| **50% LOAD (9/27/96)** | | | | | |
| Sample Time | 1335 - 1351 | 1359 - 1415 | 1423 - 1439 | | - - |
| Load, MW | 65.46 | 65.54 | 65.13 | 65.38 | - - |
| ppmvd $NO_x$ | 6.6 | 6.9 | 7.0 | 6.8 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 6.7 | 7.0 | 7.1 | 6.9 | 9 |
| Flow Rate, dscfh | 2.42 E+07 | 2.42 E+07 | 2.41 E+07 | 2.42 E+07 | - - |
| lb $NO_x$/hr | 19.12 | 19.80 | 20.17 | 19.70 | 35.0 |
| **30% LOAD (9/27/96)** | | | | | |
| Sample Time | 1454 - 1510 | 1518 - 1534 | 1542 - 1558 | | - - |
| Load, MW | 60.47 | 59.87 | 60.30 | 60.21 | - - |
| ppmvd $NO_x$ | 6.6 | 6.8 | 6.9 | 6.8 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 6.6 | 6.8 | 6.9 | 6.8 | 9 |
| Flow Rate, dscfh | 2.25 E+07 | 2.24 E+07 | 2.24 E+07 | 2.24 E+07 | - - |
| lb $NO_x$/hr | 17.78 | 18.30 | 18.47 | 18.18 | 35.0 |

**TABLE 2-6**
**COMPLIANCE TEST RESULTS**
**UNIT NO. 2 STACK - NO. 2 FUEL OIL**
**OCTOBER 1996**

| No. 2 Fuel Oil | Rep 1 | Rep 2 | Rep 3 | Average | Permit Limit |
|---|---|---|---|---|---|
| **100% LOAD (10/10/96)** | | | | | |
| Sample Time | 1200 - 1216 | 1445 - 1501 | 1730 - 1746 | | - - |
| Load, MW | 78.78 | 78.71 | 79.14 | 78.88 | - - |
| ppmvd $NO_x$ | 47.1 | 47.0 | 46.0 | 46.7 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 44.8 | 45.4 | 43.9 | 44.7 | 54 |
| Flow Rate, dscfh | 2.83 E+07 | 2.83 E+07 | 2.90 E+07 | 2.85 E+07 | - - |
| lb $NO_x$/hr | 159.23 | 158.86 | 159.15 | 159.08 | 239.0 |
| **75% LOAD (10/14/96)** | | | | | |
| Sample Time | 1128 - 1144 | 1149 - 1205 | 1210 - 1226 | | - - |
| Load, MW | 70.09 | 70.24 | 70.14 | 70.16 | - - |
| ppmvd $NO_x$ | 48.4 | 49.9 | 49.1 | 49.1 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 45.5 | 47.3 | 46.6 | 46.5 | 54 |
| Flow Rate, dscfh | 2.53 E+07 | 2.54 E+07 | 2.55 E+07 | 2.54 E+07 | - - |
| lb $NO_x$/hr | 146.14 | 151.04 | 149.40 | 148.86 | 239.0 |
| **50% LOAD (10/14/96)** | | | | | |
| Sample Time | 1013 - 1029 | 1034 - 1050 | 1056 - 1112 | | - - |
| Load, MW | 65.03 | 64.93 | 65.01 | 64.99 | - - |
| ppmvd $NO_x$ | 49.8 | 51.7 | 52.2 | 51.2 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 46.5 | 48.0 | 48.5 | 47.7 | 54 |
| Flow Rate, dscfh | 2.35 E+07 | 2.36 E+07 | 2.35 E+07 | 2.35 E+07 | - - |
| lb $NO_x$/hr | 140.09 | 145.49 | 146.32 | 143.97 | 239.0 |
| **30% LOAD (10/14/96)** | | | | | |
| Sample Time | 0852 - 0908 | 0914 - 0930 | 0945 - 1001 | | - - |
| Load, MW | 60.16 | 60.47 | 60.24 | 60.29 | - - |
| ppmvd $NO_x$ | 50.0 | 48.8 | 52.3 | 50.4 | - - |
| ppmvd $NO_x$ @ 15% $O_2$ | 48.9 | 47.2 | 49.8 | 48.7 | 54 |
| Flow Rate, dscfh | 2.31 E+07 | 2.32 E+07 | 2.29 E+07 | 2.31 E+07 | - - |
| lb $NO_x$/hr | 137.60 | 135.41 | 143.32 | 138.78 | 239.0 |

# ATTACHMENT V

# REVISED TABLE 7-13

Table 7-13. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

| Pollutant | Averaging Time | Maximum Impact ($\mu g/m^3$) | Significant Impact ($\mu g/m^3$) |
|---|---|---|---|
| $NO_x$ | Annual | 0.011 | 1.0 |
| CO | 8-hour | 0.7 | 500 |
| | 1-hour | 5.2 | 2,000 |
| PM | Annual | 0.002 | 1.0 |
| | 24-hour | 0.07 | 5.0 |
| $SO_2$ | Annual | 0.003 | 1.0 |
| | 24-hour | 0.23 | 5.0 |
| | 3-hour | 1.74 | 25.0 |

Source: ECT, 1999.

# INTEROFFICE MEMORANDUM

**Date:** 21-Jul-1999 09:45am
**From:** Tom Davis
tdavis@ectinc.com
**Dept:**
**Tel No:**

**To:** Jeff Koerner ( Koerner_J@dep.state.fl.us )
**CC:** Chris Carlson ( Carlson_C@dep.state.fl.us )

**Subject:** - no subject (01JDTLIQNZ609BVDS6) -

Jeff,

I have reviewed summary Table 7-13. Except for NO2, it looks like I used the unadjusted model results (based on a nominal 10.0 g/s emission rate) rather than the correct adjusted rates shown in Tables 7-5 through 7-12. Also, the 1- and 8-hr CO results were reversed. I will send you a corrected Table 7-13 with the response package to your 7/15/99 letter (probably going out to you today).

Tom Davis
Environmental Consulting & Technology, Inc.

Voice: (352) 332-6230, Ext. 351
Fax: (352) 332-6722

Z 333 618 198

US Postal Service

## Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

| | |
|---|---|
| Sent to Richard Ludwig | |
| Street & Number TECO Hardee | |
| Post Office, State, & ZIP Code Tampa Fl | |
| Postage | $ |
| Certified Fee | |
| Special Delivery Fee | |
| Restricted Delivery Fee | |
| Return Receipt Showing to Whom & Date Delivered | |
| Return Receipt Showing to Whom, Date, & Addressee's Address | |
| TOTAL Postage & Fees | $ |
| Postmark or Date P50-Fl-140a | 7-15-99 |

PS Form **3800**, April 1995

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

Is your RETURN ADDRESS completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Richard Ludwig
TECO Power Services
702 N. Franklin St.
Tampa, Fl 33602

4a. Article Number
Z 333 618 198

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

7. Date of Delivery JUL 19 1999

5. Received By: *(Print Name)*

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

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

Thank you for using Return Receipt Service.

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

# Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

July 15, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Richard E. Ludwig, President
TECO Power Services
702 North Franklin Street
Tampa, FL 33602

Re: Request for Additional Information
Permit No. PSD-FL-140(a)
TECO – Hardee Power Station (PA-89-25)
Modification to Construct Additional 75 MW Gas Turbine

Dear Mr. Ludwig:

On June 18, 1999, the Department's Bureau of Air Regulation received your application and complete fee for a PSD construction permit to add a 75 MW combustion turbine to the Hardee Power Station. Our review of the application is being conducted in parallel with the other Department programs as required by the Power Plant Siting Act. We will also provide a Sufficiency Review through the Office of Power Plant Siting.

The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Specify the model of dry low-NOx, dual-fuel combustors that will be installed on the General Electric Model 7EA combustion turbine. Also, describe the combustion process using this specific combustor technology from startup to base load operation.
2. Specify the control system that will control the combustion process. What parameters are input to this control system? What processes and functions are controlled by this system?
3. Provide letter from the manufacturer stating that the guarantees for CO / NOx emissions (25 / 9 ppmvd at 15% oxygen) are for continuous operation with dual-fuel combustors. Also, provide manufacturer performance curves showing the CO and NOx emissions characteristics from startup to 100% base load for the combustion turbine.
4. Provide the test results summary (CO, NOx, and VOC) for a similarly designed, existing General Electric 7EA Model PG7121 conducted within the last two years.

5. Provide the modeling output files on computer diskette.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. Thomas W. Davis, ECT
Mr. Paul L. Carpinone, TECO
Mr. Buck Oven, Siting Office
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Phil Barbaccia, SW District - DEP

# INTEROFFICE MEMORANDUM

**Date:** 08-Jul-1999 06:19pm
**From:** Ellen_Porter
Ellen_Porter@nps.gov
**Dept:**
**Tel No:**

**To:** linero_a ( linero_a@dep.state.fl.us )
**To:** koerner_j ( koerner_j@dep.state.fl.us )
**To:** holladay_c ( holladay_c@dep.state.fl.us )
**CC:** Don_Shepherd ( Don_Shepherd@nps.gov )

**Subject:** Hardee Power Station

We are pleased to see that Hardee's new simple-cycle turbine will meet a NOx emission limit of 9 ppm when burning gas.

We agree that because of the distance of the project from Chassahowitzka (130 km) and the types and amounts of emissions (NOx=199 tpy; PM=24 tpy; SO2=44 tpy), there is low potential for impacts to the Class I area. We have no further comments.

# Department of
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 24, 1999

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

Re: Hardee Power Station PA 89-25
Modification of Certification

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above-mentioned project. The applicant proposes to install a General Electric Model PG7121 combustion gas turbine with electrical generator rated at 75 MW. The unit will operate in simple cycle mode and be fired primarily with natural gas and have low sulfur distillate oil as a backup. The proposed BACT emissions were 25/20 ppmvd of CO and 9/42 ppmvd of NOx for gas and oil firing.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at 850/922-6979. If you have any questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

Kim Tober

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

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 24, 1999

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

Re: Hardee Power Station PA 89-25
Modification of Certification

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above-mentioned project. The applicant proposes to install a General Electric Model PG7121 combustion gas turbine with electrical generator rated at 75 MW. The unit will operate in simple cycle mode and be fired primarily with natural gas and have low sulfur distillate oil as a backup. The proposed BACT emissions were 25/20 ppmvd of CO and 9/42 ppmvd of NOx for gas and oil firing.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at 850/922-6979. If you have any questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

Kyn Tober
for

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

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

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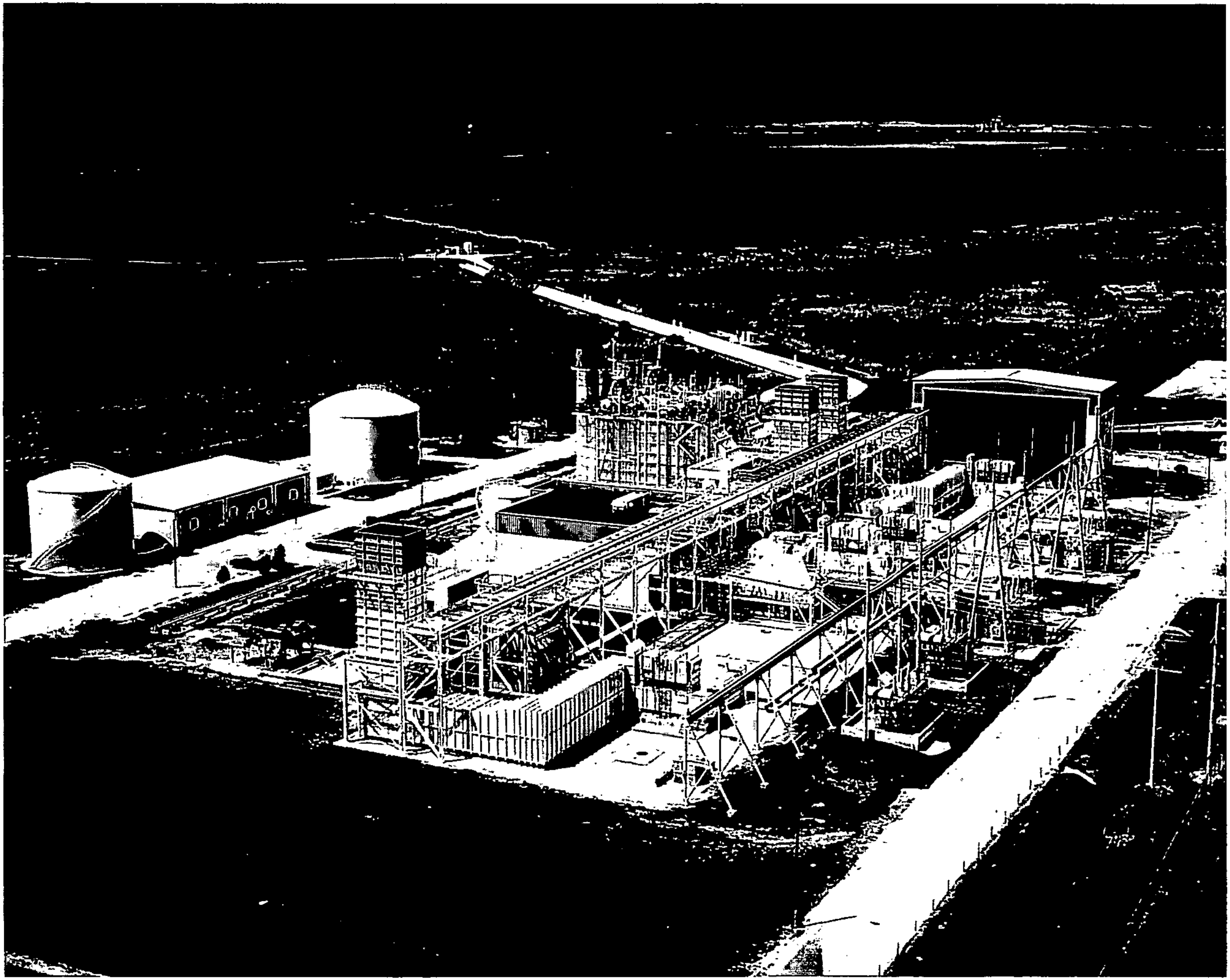

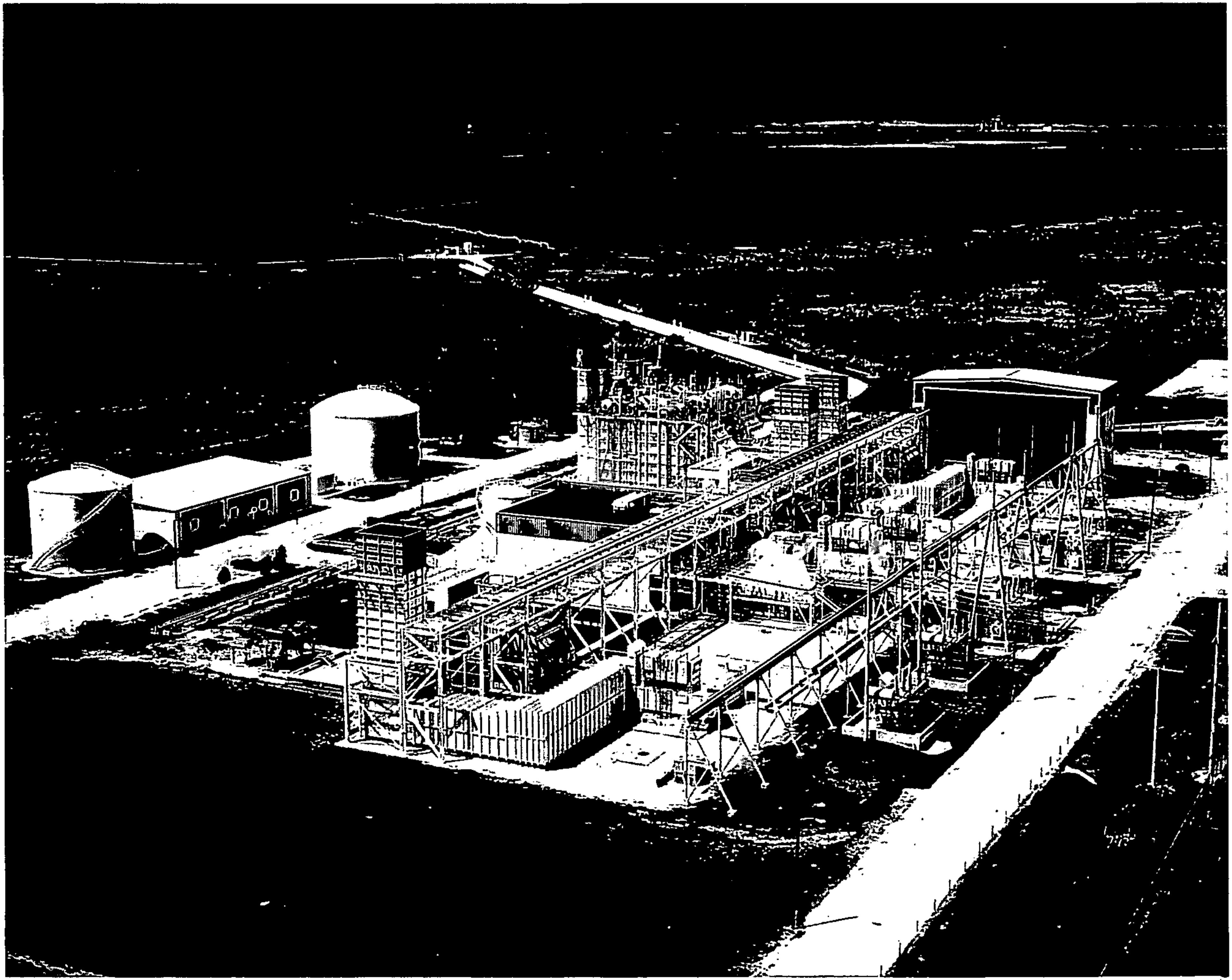

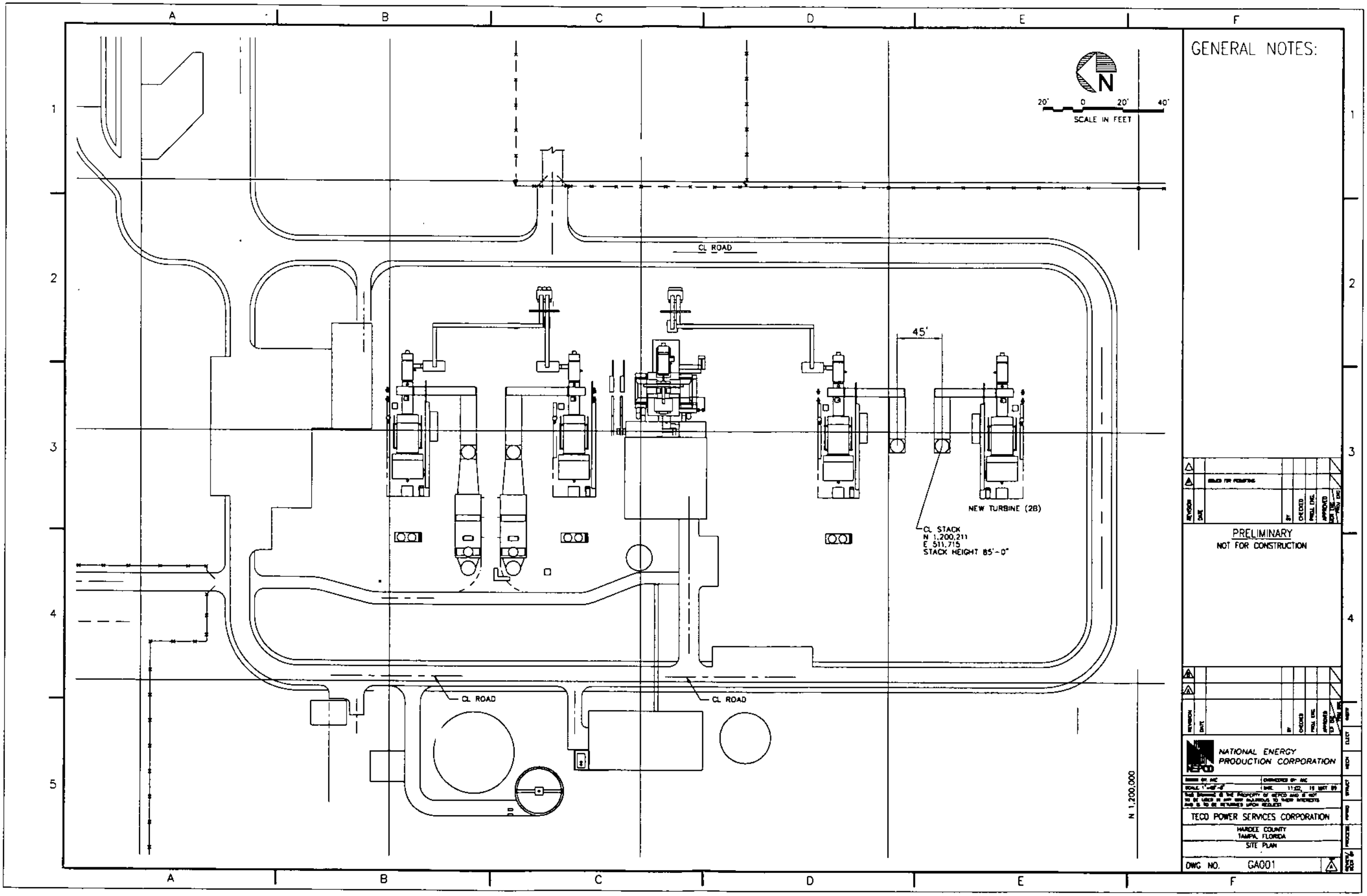
GENERAL NOTES:
N
20' 0 20' 40'
SCALE IN FEET
CL ROAD
45'
NEW TURBINE (2B)
CL STACK
N 1,200,211
E 511,715
STACK HEIGHT 85'-0"
CL ROAD
CL ROAD
N 1,200,000
PRELIMINARY
NOT FOR CONSTRUCTION
NATIONAL ENERGY PRODUCTION CORPORATION
TECO POWER SERVICES CORPORATION
HARDEE COUNTY
TAMPA, FLORIDA
SITE PLAN
DWG NO. GA001

6-8-99

Meeting at Power Plant Siting Office

TECO
Hardie Power Station

- Near Seminole, Payne Creek
- Consultant - Jack Doolittle - ECT
- Want to add a 7E (GE) 75 MW, simple cycle combustion turbine to existing plant (Unit 2-B?)
  - → Fired w/natural gas and oil backup fuel
  - → DLN on gas to $NO_x \leq 9$ ppmvd, $\leq 25$ ppmvd of CO
  - → water injection on oil to $\leq 42$ ppmvd
  - → 876 hour/year of oil
  - → No new oil storage tank or cooling tower necessary
  - → Want up to 8760 hour/year on gas
  - → Dept. needs good information on "hot" SCR (have a bid in to Englehard)