Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 1, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Benjamin M.H. Borsch, P.E.
Santa Rosa Energy Center, LLC
2701 N. Rocky Point Drive, Suite 1200
Tampa, Florida 33607

Re: Santa Rosa Energy LLC
DEP File No. 1130168-003-AC (PSD-FL-253)
Change in Inlet Cooler Design and Non-installation of Duct Burner

Dear Mr. Borsch:

The Department acknowledges receipt of your letter dated March 13, 2002, requesting the replacement of the evaporative cooler for the General Electric Spray Inlet Temperature Suppression (SPRITS) system and the deletion of the duct burners from the construction permit.

Based on your information and our review of your request, the Department accepts the installation of the SPRITS system instead of the evaporative cooler and the deletion of all references to the duct burners from the construction permit. A modification of the conditions of the construction permit reflecting your request will take effect during the processing of the Title V permit.

A copy of this letter shall be part of your records. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

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

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

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

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

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

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

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

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

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

Executed in Tallahassee, Florida

CH Jones
for Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4/1/02 to the person(s) listed:

Benjamin M.H. Borsch, P.E.*
Sandra Veazey, DEP NWD
Gregg Worley, EPA

Clerk Stamp

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

Victoria Gibson April 1, 2002
(Clerk) (Date)

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Benjamin M.H. Borsch, P.E.
Santa Rosa Energy Center, LLC
2701 N. Rocky Point Dr.
Suite 1200
Tampa, FL 33607

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* R. Marzka

B. Date of Delivery 4-3-02

C. Signature X R. Margka ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. 7001 0320 0001 3692 9052

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7001 0320 0001 3692 9052

OFFICIAL USE

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To Benjamin M.H. Borsch, P.E.
Street, Apt. No.; or PO Box No. 2701 N. Rocky Pt. Dr., Ste. 1200
City, State, ZIP+4 Tampa, FL 33607

PS Form 3800, January 2001 See Reverse for Instructions

CALPINE

Santa Rosa Energy Center
5001 Sterling Way
Pace, FL 32571
850.995.2100 (Main)
850.995.1145 (FAX)

RECEIVED
MAR 27 2002
BUREAU OF AIR REGULATION

March 26, 2002

CPN-SREC-02-007

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

The enclosed Cashier's Check in the amount of $250.00 is for the fee to modify the PSD permit for the Santa Rosa Energy Center Permit Number PSD-FL-253.

Please contact me at 850-995-2100 if you have any questions.

David J. Somers, P. E.
Project Manager

Cy to: Ben Borsch, Calpine Corporation, Tampa Florida

Encl.: Cashier's Check, Bank of America, No. 1526025, dated March 26, 2002

CALPINE

ISLAND CENTER
2701 N. ROCKY POINT DRIVE
SUITE 1200
TAMPA, FLORIDA 33607
813.637.7300
813.637.7399 (FAX)

RECEIVED
MAR 19 2002
BUREAU OF AIR REGULATION

March 13, 2002

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

RE: Santa Rosa Energy Center, LLC
PSD Permit Number PSD-FL-253/1130168-001AC
Change in Inlet Cooler Design

Dear Mr. Linero:

Santa Rosa Energy Center, LLC (SREC) is nearing completion of construction of the combined cycle combustion turbine permitted under permit number PSD-FL-253/1130168-001-AC. This letter is to inform the department of certain changes being made to the installed configuration of the system in response to advice of the turbine vendor as well as changes in business conditions. There are two primary changes each explained in more detail below. The first change will be the replacement of the evaporative cooler permitted for use on the system with the General Electric Spray Inlet Temperature Suppression (SPRITS) system. The second change is the elimination of the permitted duct burners from the system. The effect of these changes will be a reduction in permitted emissions from the unit. SREC requests that the department make appropriate changes to permit number PSD-FL-253/1130168-001AC to accommodate these changes as outlined below.

SREC proposes to replace the permitted evaporative coolers with the GE supplied SPRITS system. Performance data for the combustion turbine using the SPRITS system is shown in Attachment 1. This data is shown in comparison to the evaporative cooler performance data initially submitted to the department as part of the air permit application. The vendor rates the effectiveness of each system at 85%, thus the thermal performance of the two systems is essentially equal. The SPRITS system provides the inlet cooling effect with a lower inlet pressure drop, allowing a slightly higher unit output (600 kW). Data shown in Attachment 1 for unit operation with the SPRITS has also been revised to reflect a more accurate assessment of the local fuel gas characteristics and thus shows some minor changes in exhaust analysis. The change in anticipated gas quality result in a small reduction in the number of pounds per hour of NOx emitted. This change is not related to the change in inlet cooling systems, which is estimated to have no impact on the facility emissions.

SREC considers the change from the permitted evaporative cooler to the SPRITS system to be a non-material change, reflecting the supply of the vendor's most recent equivalent design. SREC also recognizes the department's need to review such changes to determine that they do not represent physical changes resulting in significant increases in output. Accordingly, SREC requests that the department indicate concurrence that this is a non-material change, or issue a modification to the facility PSD permit, number PSD-FL-253/1130168-001AC reflect the installation and operation of the SPRITS system. The SPRITS system will be installed following notice of approval from the department.

SREC has decided not to install the previously permitted duct burners. Output from the unit will result from the operation of the combustion turbine alone, with the SPRITS system discussed above as permitted. This change will be reflected in the deletion of unit tests with the duct burners. SREC recognizes that a decision not to test the duct burners at the time of the initial plant compliance tests will result in no permission to operate the unit with duct burning, and the likely need for a permit modification if a decision is made in the future to install duct burners. It is SREC's intention to request deletion of the duct burners from the permit during the Title V permit application process.

SREC is fully intending to prepare for initial operation in time to complete compliance testing prior to the June 30, 2002 date established in the facility's PSD permit. Appropriate notices to the department regarding test protocols, initial operation dates, and dates of compliance testing will be provided separately to the department.

We appreciate your prompt consideration of this issue. If you have questions, or would like to have additional information regarding this issue, please do not hesitate to contact me via telephone at (813) 637-7305 or via email at bborsch@calpine.com.

Sincerely,

SANTA ROSA ENERGY CENTER, LLC

Benjamin M. H. Borsch

Benjamin M. H. Borsch, P.E.
Environmental Manager

ATTACHMENT 1

HEAT INPUT AND EMISSIONS DATA

SPRITS OPERATION

The first of two attached pages show data provided by the combustion turbine vendor showing expected unit performance including the operation of the SPRITS system. The second page shows the performance with the permitted evaporative cooler. This second page of data is the same as provided previously in the PSD permit application dated June 1999.

Data provided for the SPRITS unit also reflects performance using the most recent estimate of expected natural gas quality local to the site. Some minor changes in performance, including a very slight reduction in lb/hr NOx emissions results from a lower expected heat capacity of the gas compared to the 1999 data.

SANTA ROSA ENERGY CENTER - SPRITS

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Exhaust Pressure Loss	in H2O	12.8
Ambient Temperature	deg F	68.
SPRITS Status		On
Output	kW	168,500.
Heat Rate (LHV)	Btu/kWh	9,450.
Heat Cons. (LHV)	MBtu/hr	1,592.3
Exhaust Flow x10^3	lb/hr	3512.
Exhaust Temperature	deg F	1126.
Exhaust Energy (Heat Bal)	MBtu/hr	962.8

EMISSIONS

NOx	ppmvd @ 15% O2	9.
NOx AS NO2	lb/hr	58.
CO	ppmvd	9.
CO	lb/hr	28.
UHC	ppmvw	7.
UHC	lb/hr	14.
VOC	ppmvw	1.4
VOC	lb/hr	2.8
PM10 (Front + Back Half)	lb/hr	18.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	73.96
Oxygen	12.34
Carbon Dioxide	3.84
Water	8.98

SITE CONDITIONS

Elevation	ft	90.0
Site Pressure	psia	14.65
Inlet Loss	in H2O	3.0
Exhaust Loss	in H2O	13.0 @ ISO Conditions
Relative Humidity	%	60
Fuel Type		Cust Gas – Hog Bayou 022500
Fuel LHV	Btu/lb	21381 @ 77F
Fuel Temperature		160 °F
Application		Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

PM10 emissions assume 0.0 %w fuel sulfur content.

IPS- 92422 Version Code - 3.1.1/30A1/2.2.8/PG7241-1298
FERREIFE 12/21/2001 16:11 122101 68F HogBayouGas SPRITS.dat
Exh energy adj for fuel heat to 160F

General Electric Proprietary Information

NOV. 6.1997 10:46AM **Best Available Copy**

POLSKY ENERGY CORPORATION
ESTIMATED PERFORMANCE - PG7241(FA)

LOAD CONDITION			BASE	75%	65%	50%
AMBIENT TEMP.		- Deg F.	68	68	68	68
AMBIENT RELATIVE HUMID		- %	60	60	60	60
OUTPUT		- kW	168300.	126200.	109400.	84200.
HEAT RATE (LHV)		- Btu/kWh	9460.	10250.	10900.	12330.
HEAT CONS. (LHV)	X10-6	- Btu/h	1592.1	1293.5	1192.5	1038.2
EXHAUST FLOW	X10-3	- lb/h	3507.0	2884.0	2685.0	2385.0
EXHAUST TEMP		- Deg F.	1122.	1147.	1164.	1192.
EXHAUST HEAT	X10-6	- Btu/h	971.8	824.8	783.5	719.1

		BASE	75%	65%	50%
NOX	- ppmvd @ 15% O2	9.	9.	9.	9.
NOX AS NO2	- lb/h	59.	47.	43.	37.
CO	- ppmvd	9.	9.	9.	9.
CO	- lb/h	28.	23.	22.	19.
UHC	- ppmvw	7.	7.	7.	7.
UHC	- lb/h	14.	11.	11.	9.
SO2	- ppmvw	0.	0.	0.	0.
SO2	- lb/h	1.	1.	1.	1.
SO3	- ppmvw	0.	0.	0.	0.
SO3	- lb/h	0.	0.	0.	0.
SULFUR MIST	- lb/h	0.	0.	0.	0.
PART	- lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.				
ARGON	0.88	0.89	0.88	0.88
NITROGEN	73.94	74.20	74.24	74.31
OXYGEN	12.28	12.50	12.61	12.82
CARBON DIOXIDE	3.96	3.88	3.83	3.73
WATER	8.94	8.54	8.44	8.26

SITE CONDITIONS
****

ELEVATION	- ft.	60
SITE PRESSURE	- psia	14.67
INLET LOSS	- in. Water	4.5
EXHAUST LOSS	- in. Water	12
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20431
APPLICATION	-	7FH2 HYDROGEN-COOLED GENERATOR
COMBUSTION SYSTEM	-	9/42 DLN COMBUSTOR

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE
NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
THE FUEL HAS .2GRAINS/100SCF OF SULFUR.
THIS PERFORMANCE INCLUDES THE EFFECTS OF AN 85 % EFFECTIVE EVAPORATIVE COOLER.
THE COOLER IS TURNED ON FOR BASE LOAD ONLY.

IPS-70447 POLSKY7F version code-0597D-0597E-0597D-0 N
JBS 06-Nov-97 09:41 AM

CALPINE

650 DUNDEE ROAD
SUITE 350
NORTHBROOK, ILLINOIS 60062
847.559.9800
847.559.1805 (FAX)

January 7, 2002

RECEIVED
JAN - 7 2002
Bureau of Air Monitoring & Mobile Sources

Florida Department of Environmental Protection
Division of Air Resource Management, MS5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Change of Authorized Representative
Santa Rosa Energy Center
Facility ID Number-1130168
PSD Permit Number-PSD-FL-253
Fed Ex Number-831882221280

On behalf of Santa Rose Energy Mr. Benjamin M. H. Borsch, Environmental Manager for Calpine Corporation, is the new authorized representative for the Santa Rosa Energy Center's Prevention of Significant Determination Permit (PSD-FL-253). If you have any questions or concerns, please feel free to call myself at (617) 723-7200 or Benjamin Borsch at (813) 637-7300.

Sincerely,

James Shield

James Shield
Vice President—Project Management

CC: Benjamin M.H. Borsch, Calpine—Tampa
Dave Somers, Santa Rosa—Construction
Dane Hill, Santa Rosa—Operations

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

February 19, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. David Plauck
SkyGen/Santa Rosa Energy LLC
650 Dundee Road, Suite 350
Northbrook, Illinois 60062

Re: Santa Rosa Energy LLC
DEP File No. PSD-FL-253

Dear Mr. Plauck:

The Department acknowledges receipt of your letter dated January 26, 2001, notifying the Department that SkyGen/Santa Rosa determined that the UTM coordinates provided with the permit application for the location of the stack were in error. The letter states that the new stack location based on the corrected UTM coordinates is approximately 580 feet south of the location presented in the permit application, which is further away from the Sterling Fiber plant proper. The letter further states that the stack parameters and emission rates have not changed, and that no additional air dispersion modeling is required. The department concurs that no additional modeling is required and that no additional preconstruction review requirements are necessary to correct the UTM coordinates for the stack location. The modeling analysis conducted for the original stack location indicated ambient impacts well below the PSD significance levels. Since there has been no change in the relationship between the modeled receptor grid and the facility layout of the new and old stack location, the department concurs that the modeling results would continue to show impacts well below the PSD significance levels.

In accordance with your request the corrected UTM coordinates will be made a part of the file.

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

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

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Executed in Tallahassee, Florida.

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/21/01 to the person(s) listed:

David Plauck, SkyGen/Santa Rosa*
James Shield, SkyGen/Santa Rosa*
Silvia Alderman, Esq.
Ed Middleswart, DEP NWD
Gregg Worley, EPA

Clerk Stamp

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

Charlotte J. Hayes 2/21/01
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

BAR

THRU: ~~A.A. Linero~~ C.H. Fancy CHF

FROM: Cleve Holladay

DATE: February 19, 2001

SUBJECT: Santa Rosa Energy Center 241 MW Cogeneration Project
DEP File No. PSD-FL-253

Attached is a letter addressing Santa Rosa Energy Center (SREC) concerns regarding previously submitted information.

Santa Rosa notified the Department that the UTM coordinates provided with the permit application for the location of the stack were in error. The letter states that the new stack location based on the corrected UTM coordinates is approximately 580 feet south of the location presented in the permit application, which is further away from the Sterling Fiber plant proper. The letter further states that the stack parameters and emission rates have not changed, and that no additional air dispersion modeling is required.

The Department concurs that no additional modeling is required and that no additional preconstruction review requirements are necessary to correct the UTM coordinates for the stack location. The modeling analysis conducted for the original stack location indicated ambient impacts well below the PSD significance levels. Since there has been no change in the relationship between the modeled receptor grid and the facility layout of the new and old stack location, the Department concurs that the modeling results would continue to show impacts well below the PSD significance levels.

We recommend your approval.

AAL/ch

Attachments

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. James Shield
SkyGen/Santa Rosa Energy LLC
650 Dundee Rd., Ste 350
Northbrook, IL 60062

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 2-26-01

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 3676

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1449 3676

Article Sent To:
Mr. James Shield

Postage	$	SantaRosa
Certified Fee		Postmark Here
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
Mr. James Shield
Street, Apt. No.; or PO Box No. 650 Dundee Rd., Ste 350
City, State, ZIP+4 Northbrook IL 60062

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. David Plauck
SkyGen/Santa Rosa Energy LLC
650 Dundee Road, Suite 350
Northbrook, IL 60062

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 2-26-9

C. Signature
X [signature]
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 3706

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1449 3706

Article Sent To:
Mr. David Plauck

Postage	$	Santa Rosa Energy
Certified Fee		Postmark Here
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
David Plauck
Street, Apt. No.; or PO Box No.
650 Dundee Rd., Ste 350
City, State, ZIP+4
Northbrook, Il 60062

PS Form 3800, July 1999 See Reverse for Instructions

Santa Rosa Energy LLC
650 Dundee Road
Suite 350
Northbrook, Illinois 60062
tel 847 559 9800
fax 847 559 1805
www.skygen.com

skygen
A CALPINE COMPANY

January 26, 2001

Mr. A.A. Linero
Administrator, New Source Review Section
Division of Air Resources Management
State of Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

RECEIVED
JAN 29 2001
BUREAU OF AIR REGULATION

Re: Santa Rosa Energy Center
Permit No. PSD-FL-253
Stack Location Correction

Dear Mr. Linero:

Santa Rosa LLC is preparing to begin construction of its combined cycle cogeneration facility to function in conjunction with the Sterling Fibers, Inc. facility located in Pace, Florida. The Florida Department of Environmental Protection (FDEP) has issued Permit No. PSD-FL-253 authorizing construction of the cogeneration facility.

During the detail design phase of the project, Santa Rosa LLC determined that the UTM coordinates provided with the application were in error. As you know the cogeneration facility is to be constructed immediately attached to the Sterling plant, as shown on the permit drawings. The UTM coordinates listed in the application do not coincide with this location. The permit drawings are correct; the UTM coordinates are not. All air dispersion modeling was conducted using the stack location presented in the permit application.

Santa Rosa LLC requested that Roy F. Weston, Inc. (WESTON®), who prepared the original permit application, review the stack location change and the impact on the original air dispersion modeling. The orientation of the equipment is the same as presented in the application and no structure dimensions have changed that would influence downwash in addition to the cogeneration facility itself. The original stack location was at the following Zone 16 UTM coordinates:

488.970 km E
3,381.350 km N

The new UTM coordinates, still in Zone 16, are:

488.974 km E
3,381.526 km N

The new stack location is, therefore, approximately 580 feet south of the location presented in the permit application, which is further away from the Sterling Fiber plant proper coinciding with the location shown on the permit drawings. The stack parameters and emission rates have not changed.

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A CALPINE COMPANY

The modeling analysis conducted for the original stack location indicated that ambient air impacts were substantially less than the PSD significance levels. Since the relationship between the modeled receptor grid and the facility layout for the new and old stack location would be the same, the modeling results should remain the same and continue to show insignificant impacts. Santa Rosa LLC therefore believes that no additional modeling is necessary for the stack relocation because the conclusions reached using the modeling analysis in the permit application will not be changed. Santa Rosa LLC requests that FDEP review the stack relocation and provide a written concurrence that the change in the UTM coordinates does not subject the facility to further preconstruction review requirements. We also request that the corrected UTM coordinates be made a part of the file.

Your prompt concurrence on this matter would be appreciated, since Santa Rosa LLC is ready to begin construction. If you have any questions, please call me at 847-559-7800, extension 311.

Sincerely,

Santa Rosa Energy LLC
by its Managing Member
SkyGen Energy LLC

David Plauck
Project Manager

cc: Theresa Heron, FDEP
Silvia Alderman
Dave Somers
Ben Borsch

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 25, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. David Plauck
SkyGen/Santa Rosa Energy LLC
650 Dundee Road, Suite 350
Northbrook, Illinois 60062

Re: Santa Rosa Energy LLC
DEP File No. 1130168-002-AC (PSD-FL-253)

Dear Mr. Plauck:

The Department acknowledges receipt of your letter (and revised construction schedule) dated May 22, 2000 notifying the Department that SkyGen/Santa Rosa has commenced construction in accordance with Section II, Condition 6 of the referenced permit. The letter also requests an extension of six months to complete the project.

During the permitting of the unit, EPA advised that several projects in the region using the same model of turbine as proposed for Santa Rosa planned to install selective catalytic reduction (SCR) and to meet lower nitrogen oxides limits than your project. Among these is SkyGen's Mobile Energy LLC project which received a permit from the State of Alabama at about the same time as SkyGen/Santa Rosa received its permit from Florida. Some of the affected projects will also be completed prior to the expiration date in your existing permit.

Based on your notification that construction has commenced and the construction status of key components being purchased from General Electric, it should be easily possible to complete construction in another two years. In accordance with your request and the revised construction schedule, the Department hereby extends the expiration date of the permit from December 31, 2001 to June 30, 2002. Any further extensions will include a requirement to install SCR and comply with an appropriately lower limit to be set at that time by the Department.

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

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

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

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

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

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

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

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

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

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5-30-00 to the person(s) listed:

David Plauck, SkyGen/Santa Rosa*
James Shield, SkyGen/Santa Rosa*
Silvia Alderman, Esq.
Ed Middleswart, DEP NWD
Gregg Worley, EPA

Clerk Stamp

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

Kim Tober 5-30-00
(Clerk) (Date)

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. David Plauck
Sky Gen / Santa Rosa Energy
650 Dundee Rd
Suite 350
Northbrook, IL
60062

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6/2/00

C. Signature X [signature] ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. A ... 301

PS Form ...

102595-99-M-1789

Z 341 355 301

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

Sent to	David Plauck
Street & Number	Sky Gen / SANTA
Post Office, State, & ZIP Code	& ROSA En.
Postage	Northbrook, IL
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	5-30-00

1130168-002-AC
PSD-F1-253

PS Form **3800**, April 1995

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. James Shield
Santa Rosa Energy
650 Dundee Rd, Suite 150
Northbrook, IL
60062

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6/2/00

C. Signature X J Bellandi ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* Z 341 355 300

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Z 341 355 300

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

Sent to James Shield	
Street & Number Sky Gen/Santa	
Post Office, State, & ZIP Code Rosa En.	
Postage North Brook, IL	
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 5-30-00 1130168-002-AC P0D-F1-253	

PS Form **3800**, April 1995

Santa Rosa Energy LLC
650 Dundee Road
Suite 350
Northbrook, Illinois
60062
tel 847 559 9800
fax 847 559 1805
www.skygen.com

skygen

May 22 2000
Letter No. 88

RECEIVED
MAY 23 2000
BUREAU OF AIR REGULATION

Alvaro A. Linero, P.E.
Bureau of Air Quality Management
State of Florida
Department of Environmental Protection
2600 Blair Stone Road
Mail Station 5505
Tallahassee, Florida 32399-2400

1130168-002-AC
PSD-FL-253a

Re: Santa Rosa Energy LLC
Permit No. PSD-FL-253

Dear Mr. Linero:

Thank you and Teresa Heron for meeting with us on Tuesday, May 2, 2000 to discuss the Santa Rosa Energy Center (the "Project"). As you are aware, the Project is being developed by Santa Rosa Energy LLC, an affiliate of SkyGen Energy LLC. SkyGen Energy LLC and Santa Rosa Energy LLC have both been closely involved in this project. Since the facility received an air permit on December 4, 1998, the following activities have taken place:

1. An Electrical Interconnection Agreement with Gulf Power was executed on July 12, 1999, to allow the interconnection to the Gulf Power Transmission & Distribution System. This requires construction of a 7.5 mile 230 kV power line and a substation to tie into Gulf Power's existing 230 kV system, at the expense of Santa Rosa Energy LLC. Gulf Power has proceeded with land and easement acquisition along with engineering for this and has currently invoiced Santa Rosa Energy LLC approximately $240,000.

2. A construction contract was negotiated and executed on August 20, 1999, between Gilbert Industrial Corporation and Santa Rosa Energy LLC. Gilbert Industrial will design, procure all equipment (except, as set forth below, the combustion turbine and steam turbine), construct and start-up the facility upon notice to proceed from Santa Rosa Energy LLC. Under the terms of the contract, the construction notice to proceed is contingent upon approval of construction financing. However, to date, Gilbert Industrial has performed activities in excess of $400,000.

3. An Energy Services Agreement, and Lease Agreement were executed on September 20, 1999, between Sterling Fibers and Santa Rosa Energy LLC. This Agreement allows Santa Rosa Energy LLC to construct the cogeneration project at the Sterling Fibers manufacturing facility in Pace, Florida. These Agreements spell out responsibilities of each party and, to that measure, the following items have occurred:

   - The Project area has been re-zoned to proper classification for construction of the project.

   - The deep well injection permit was modified to allow the discharge from the project.

   - The consumptive use permit was modified to allow Sterling Fibers to supply sufficient water to the project. This required an extensive modeling analysis at significant costs Sterling Fibers and Santa Rosa Energy LLC.

   - Mechanical interfaces or tie-ins have been designed and completed at the site for the 600 psig and steam system, the 60 psig steam system, the condensate (return) system and the demineralized water system. These tie-ins allow the cogeneration project to tie into the existing manufacturing facility.

4. A contract was executed between SkyGen Energy LLC and GE for the purchase of a steam turbine. Due to the pressure and quality of the steam Sterling requires for its manufacturing process, this steam turbine is designed specifically for this project. At this time, the steam turbine has been partially constructed by GE for a price of almost $10,000,000, of which SkyGen Energy LLC has paid over $3,000,000.

5. A contract between GE and SkyGen Energy LLC for the combustion turbine has been executed with substantial deposit (approximately $3,200,000) with a delivery date to be determined based completion of financing the project. Financing is expected to occur during the second or third quarter of 2000.

In addition to the items listed above, significant work has been performed on the overall project development necessary to proceed with financing the project. Santa Rosa Energy LLC and SkyGen Energy LLC have spent approximately $8 million since the air permit was issued. The majority of this has been on the equipment described above. The final agreement necessary to complete project financing is being negotiated at this time and, once complete, full mobilization

skygen

will occur along with project financing. The project is currently scheduled to start-up late in the second quarter of 2002. Please see attached project milestone schedule for additional information.

Based on the above information, Santa Rosa Energy LLC believes it has complied with permit condition #6 Section II, Administrative Requirement and hereby notifies Florida Department of Environmental Protection that it has commenced construction. Should the Department not concur in that determination, please consider this letter to be a request for extension of the 18 month "commence construction" requirement specified in the permit for a period of six months (June 7, 2000 to December 7, 2000). Additionally, please consider this letter a request for extension of the construction permit expiration date for a period of approximately six months (January 1, 2002 to July 1, 2002) to accommodate the start-up described above. Enclosed is a check in the sum of $250 made out to the Florida Department of Environmental Protection, to constitute a permit modification fee. Please confirm in writing that this is acceptable to the Department and if you have any questions or need additional information, please feel free to contact me at 847-559-9800 x311.

In addition, Santa Rosa Energy understands that should the operation date be delayed significantly beyond the projected operation date described above, Santa Rosa Energy will notify FDEP and provide the documentation and Best Available Control Technology analysis necessary to install Selective Catalytic Reduction at the Santa Rosa Energy Center.

I certainly appreciate your cooperation and timely response.

Sincerely,

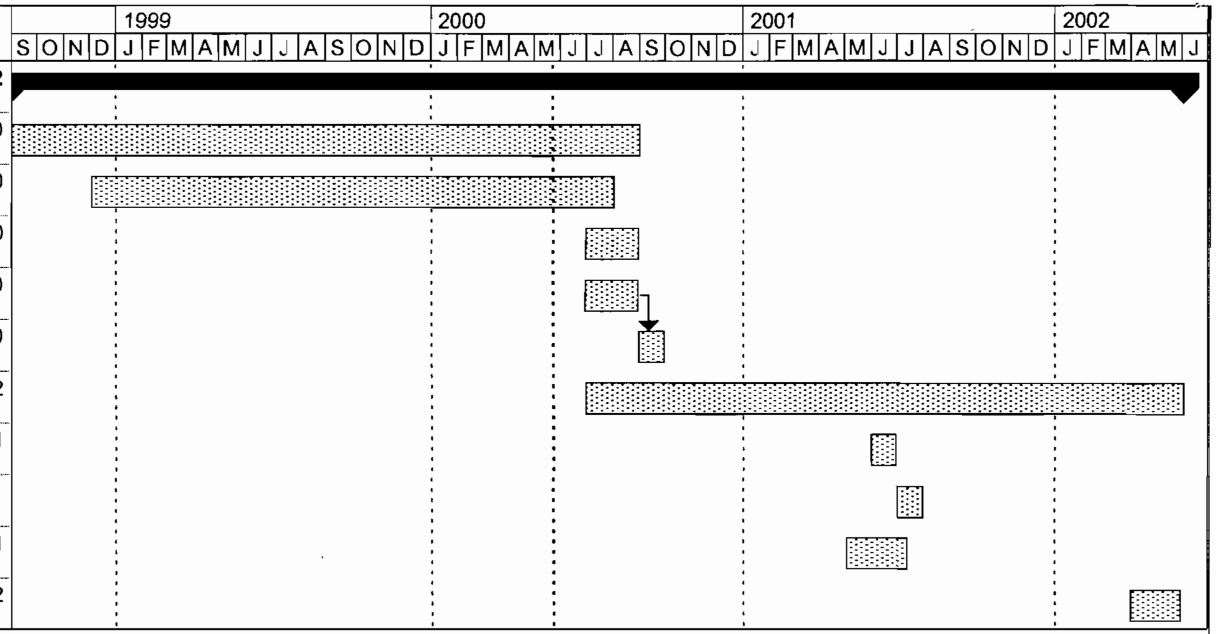
Santa Rosa Energy LLC
by its Managing Member
SkyGen Energy LLC

David Plauck
Project Manager

Enclosure
cc: Teresa Heron
Silvia Alderman

cc: NWD
EPA
NPS

ID	Task Name	Start	Finish
1	**Schedule**	**Tue 9/1/98**	**Mon 6/3/02**
2	Development & Pre-Constr	Tue 9/1/98	Fri 9/1/00
3	Finalize Agreements	Fri 12/4/98	Tue 8/1/00
4	Finance	Fri 6/30/00	Wed 8/30/00
5	Limited Release	Fri 6/30/00	Wed 8/30/00
6	Full Release for Const.	Thu 8/31/00	Fri 9/29/00
7	Construction	Fri 6/30/00	Mon 6/3/02
8	ST Delivered	Fri 6/1/01	Fri 6/29/01
9	CT Delivered	Mon 7/2/01	Tue 7/31/01
10	Elect. Inter. Complete	Fri 5/4/01	Thu 7/12/01
11	Start-up and Testing	Mon 4/1/02	Fri 5/31/02



Santa Rosa Construction Schedule-DEP
Date: Mon 5/22/00

Task
Progress
Milestone
Summary
Rolled Up Task
Rolled Up Milestone
Rolled Up Progress
Split
External Tasks
Project Summary

THIS CHECK IS VOID WITHOUT A BLUE & RED BACKGROUND AND A TRUE WATERMARK - HOLD UP TO THE LIGHT TO VERIFY

SKYGEN ENERGY LLC
650 DUNDEE ROAD, SUITE 350
NORTHBROOK, IL 60062
PH: 847-559-9800

AMERICAN NATIONAL BANK
AND TRUST COMPANY OF CHICAGO
CHICAGO, IL 60690
2-77-710

31440

DATE 5/22/2000

AMOUNT ***250.00

PAY Two Hundred Fifty and 00/100******

TO THE ORDER OF
FloridaDept Of Environ Protect
2600 Blair Stone Road
Mail Station 5505
Tallahassee, FL 32399-2400

CHECK IS PRINTED ON SECURITY PAPER WHICH INCLUDES FLUORESCENT & VISIBLE FIBERS. BORDER CONTAINS MICROPRINTING

⑈[redacted]⑈ ⑆[redacted]⑆ [redacted]⑈

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

DEC 23 1998

RECEIVED

DEC 28 1998

BUREAU OF
AIR REGULATION

4APT-ARB

Mr. A. A. Linero, P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJECT: Request for approval of a Custom Fuel Monitoring Schedule for the Santa Rosa Energy Center

Dear Mr. Linero:

Thank you for your letter of October 9, 1998, regarding the use of a custom fuel monitoring schedule for Santa Rosa Energy Center. The Santa Rosa Energy Center will be a natural gas fired congeneration facility which will have units subject to 40 C.F.R. Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. As requested, Specific Conditions 32 and 45 have been reviewed. Region 4 has concluded that the use of acid rain NO_X continuous emission monitoring system (CEMS) for demonstrating compliance, as described in Specific Condition 32, is acceptable if certain conditions are included in the permit condition. Region 4 has also concluded that the custom fuel monitoring schedule proposed in Specific Condition 45 is acceptable.

According to 40 C.F.R. 60.334(b)(2), owners and operators of stationary gas turbines subject to Subpart GG are required to monitor fuel nitrogen and sulfur content on a daily basis if a company does not have intermediate bulk storage for its fuel. 40 C.F.R. 60.334(b)(2) also contains provisions allowing owners and operators of turbines that do not have intermediate bulk storage for their fuel to request approval of custom fuel monitoring schedules that require less frequent monitoring of fuel nitrogen and sulfur content.

Region 4 reviewed Specific Condition 45 which allows SO_2 emissions to be quantified using procedures in 40 CFR 75 Appendix D in lieu of daily sampling as required by 40 CFR

60.334(b). The specific limitations listed in the permit condition are consistent with previous determinations, therefore, we conclude that the use of this custom fuel monitoring schedule is acceptable.

Specific Condition 32 involves the method used to monitor nitrogen oxides (NO_x) excess emissions. Under the provisions for 40 C.F.R. §60.334(c)(1), the operating parameters used to identify NO_x excess emissions for Subpart GG turbines are water-to-fuel injection rates and fuel nitrogen content. As an alternative to monitoring NO_x excess emissions using these parameters, Santa Rosa is proposing to use a NO_x CEMS that is certified for measuring NO_x emissions under 40 C.F.R. Part 75. Based upon the enclosed determination issued by the Environmental Protection Agency (EPA) on March 12, 1993, NO_x CEMS can be used to monitor excess emissions from Subpart GG turbines if a number of conditions specified in the determination are met and included in the permit conditions.

Finally, a NO_x CEMS used to conduct excess emission monitoring for Subpart GG must be capable of correcting results to ISO standard day conditions (i.e., 288 degrees Kelvin, 60 percent relative humidity, and 101.3 kilopascals pressure). The basis for this requirement is that, under the provisions of 40 C.F.R. §60.335(c), NO_x results from performance tests must be converted to ISO standard day conditions. As an alternative to continuously correcting results to ISO standard day conditions, Santa Rosa could keep records of the data needed to make this conversion, so that NO_x results could be calculated on an ISO standard day condition basis anytime at the request of EPA or the Florida DEP. This approach will be acceptable, since the construction permit contains NO_x limits that are more stringent than those in Subpart GG, and compliance with Subpart GG for these units would be a concern only in cases when a turbine is in violation of the NO_x limits in its permit. Therefore, converting NO_x results to ISO standard day conditions when the CEMS indicates an exceedance of the applicable permit limits, rather than converting results continuously, will provide adequate assurance of compliance with the NO_x limit in Subpart GG. For clarification, these recordkeeping and monitoring conditions must be written specifically into the permit conditions.

If you have any questions regarding the determination provided in this letter, please call David McNeal of my staff at 404/562-9102.

Sincerely,

Douglas Neeley

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

Enclosure

(1) March 12, 1993, Headquarter's guidance regarding the use of CEMS to monitor NO_x excess emissions under Subpart GG

cc: J. Heron, BAR
NWD
NPS
C. Carson, SRE
M. Cramer, RF Weston

Determination Detail

Control Number: 9400024

Category: NSPS
EPA Office: SSCD
Date: 03/12/1993
Title: NSPS Subpart GG, Alternative Method
Recipient: Karl Mangels
Author: Rasnic, John B.
Comments:

Abstract:

Can a gas turbine subject to NSPS subpart GG, and using both water injection and selective catalytic reduction to control NOx emissions use a CEMS.

Yes, the alternative of using a CEMS was approved.

Letter:

MEMORANDUM

SUBJECT: Approval of the Use of NOx CEMS as an Alternative Method to the Water-fuel Ratio Monitoring under NSPS Subpart GG

FROM: John B. Rasnic, Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

To: Karl Mangels, Chief
New York Compliance Section
Air Compliance Branch, Region II

In response to your January 12, 1993, memorandum to Linda Lay, SSCD investigated the feasibility of our approval of your request. You asked SSCD to approve a request from East Syracuse Generating Company to allow the use of the NOx continuous emission monitoring system (CEMS) as an alternative monitoring method to the continuous water-fuel ratio monitoring method.

East Syracuse Generating Company is to commence development of a 100 MW natural gas-fired cogeneration combustion turbine facility in the village of East Syracuse, New York. The facility is allowed to use a limited amount of low sulfur distillate oil as a backup fuel. To control the emissions of NOx this turbine will use both water injection and selective catalytic reduction as required by the New York State

Department of Environmental Conservation (NYSDEC). Since the NYSDEC permit conditions are more restrictive than the requirements of NSPS Subpart GG, East Syracuse is asking for a waiver from the following monitoring requirements:

1. Fuel sulfur monitoring
2. Fuel nitrogen monitoring
3. Continuous water-fuel ratio monitoring for Nox compliance.

You have already made determinations on the first two issues and asked SSCD to address only the third issue, use of NOx CEMS, that is required by the State permit, instead of the water-fuel ratio monitoring method.

SSCD determined that the use of a NOx CEMS can be allowed as an alternative monitoring method if the facility meets the following conditions:

* Each turbine meets the emission limitation (STD) determined according to 40 CFR Part 60.332. The "Y" value for the applicable equation and supporting documentation should be provided by the applicant and the limitation for NOx emissions from pipeline quality natural gas should be fixed by EPA assuming the "F" value equals 0. The emission limitation shall be expressed in ppmv, dry, corrected to 15 percent 02.

* Each N0x CEMS meets the applicable requirements of 40 CFR 560.13, Appendix B, and Appendix F for certifying, maintaining, operating and assuring quality of the system.

* Each N0x CEMS must be capable of calculating N0x emissions concentrations corrected to 15% 02 an IS0 conditions.

* Monitor data availability shall be no less than 95 percent on the quarterly basis.

* N0x CEMs should provide 4 data points for each hour and calculate a l-hour average.

* Each owner or operator of a N0x CEMS shall submit an excess emissions (calculated according to the requirements of paragraph 60.13(h)) and monitoring systems performance report and/or a summary report form to the Administrator on a quarterly basis, if excess emissions are determined, or semiannually. The report shall be postmarked by the 30th day following the end of each reporting period. Written reports shall include information required in paragraphs 60.7 (c) and 60.7 (d). This report shall also contain the content of nitrogen in fuel oil for each reporting period when oil is fired and a clearly calculated corresponding emission limitation (STD).

* Recordkeeping requirements shall follow the requirements specified in 40 CFR 560.7.

In addition, to upgrade the EPA data, we recommend that the N0x CEMS be used to demonstrate compliance with the emission limitation on a continuous basis and that the quarterly report include the N0x mass emissions for the reported period as reported to the State.

If you have any questions, please call Zofia Kosim at 703-308-8733.

cc: Air, Pesticides, and Toxics Management Division Directors Regions I and IV

Air and Waste Management Division Director

Region II

Air, Radiation, and Toxics Division Director
Region III

Air and Radiation Division Director
Region V

Air, Pesticides, and Toxics Division Director
Region VI

Air and Toxics Division Directors
Regions VII, VIII, IX, and X

SANTA ROSA *ENERGY* LLC

650 Dundee Road, Suite 150
Northbrook, Illinois 60062
Telephone (847)559-9800
Facsimile (847)559-1805

November 20, 1998
Letter No. 21

RECEIVED
NOV 23 1998
BUREAU OF
AIR REGULATION

<u>FEDERAL EXPRESS</u>

Mr. A.A. Linero
Administrator, New Source Review Section
Division of Air Resources Management
State of Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road., MS# 5505
Tallahassee, FL 32399-2400

Subject: DEP File No. 1130003-005AC (PSD-FL-253)
Santa Rosa Energy Center

Dear Mr. Linero:

Santa Rosa Energy LLC is pleased to provide the following comments to the Draft Construction Air Permit PSD-FL-253 issued by Florida Department of Environmental Protection:

1. <u>Facility Description:</u> The description indicates that the new facility will be located on the site of the steam host, Sterling Fibers, and further describes Sterling Fiber's nature of business. We request that this reference be removed in its entirety since such a reference may be viewed as a condition of the permit. Should the steam host be acquired or change the nature of its business, this should not effect the permit in any way.

2. <u>Administrative Requirements, Condition 9. Application for Title V Permit:</u> The permit does not indicate a time frame under which the application for Title V Permit must be made. We request that this condition be clarified to indicate that application for Title V permit is not required to be submitted until within twelve (12) months of start-up.

3. <u>General Operating Requirements, Condition 9. Turbine Capacity:</u> The condition indicates that the maximum fuel consumption of the turbine is 1,600 MMBtu per hour (LHV) corrected to ISO conditions. While this is the heat input of a new combustion turbine operating at 100% load at ISO conditions, the restriction does not allow for performance degradation of the combustion turbine. It is not uncommon for fuel usage to increase more than 10% at various stages of the combustion turbine's maintenance cycle. We request that this restriction be increased to a maximum heat input of 1,780 MMBtu per hour (LHV) corrected to ISO conditions.

4. General Operating Requirements, Condition 10. Heat Recovery Steam Generator Equipped with Duct Burner: The condition indicates that the natural gas usage in the Duct burner not exceed 3,280 x 10^6 scf on an annual basis. We request that this condition be changed such that the gas usage be limited to 3,280 x 10^6 scf on a twelve (12) month rolling average basis.

5. General Operating Requirements, Condition 15. Maximum Allowable Hours: Please clarify that the maximum allowable hours of operation is 8,760 ***per year***.

6. Emission Limits and Standards, Condition 20: Please clarify that the emission limits provided for in this condition are based on ISO conditions.

7. Excess Emissions, Condition 27: Please clarify that any excess emissions that result from start up or shut down of the unit are not used in calculating the 24 hour block average emissions.

Should you have any questions or require further information, please contact me at (847)559-9800 extension 325.

Sincerely,

SANTA ROSA ENERGY LLC

Craig R. Carson

Craig Carson

CRC:ag

Enclosure

ext 325

cc: J. Shield
J. Lay (Sterling Fibers
S. Alderman (Katz, Kutter)
M. Carey (Weston)

File: SRO - ENV

cc: J. Heron, BAR
NWD
EPA
NPS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an Application for Permit by:

Mr. James Shield, Vice-President
Santa Rosa Energy LLC
650 Dundee Road, Suite 150
Northbrook, Illinois 60062

DEP File No. 1130168-001AC
Permit No. PSD-FL-253
241 MW Cogeneration Facility
Santa Rosa County

Enclosed is the Final Permit Number PSD-FL-253/1130168-001 to construct a natural gas-fired 241 cogeneration facility at the Santa Rosa Energy Center, located at 5005 Sterling Way in Pace, Santa Rosa County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-4-98 to the person(s) listed:

Mr. James Shield, SRELLC *
Mr. Craig Carson, SRELLC
Mr. Mark Cramer, P.E., R. F. Weston
Mr. Ed Middleswart, DEP-NWD
Mr. Doug Neely, EPA
Mr. John Bunyak, NPS

Clerk Stamp

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

(Clerk) 12-4-98
(Date)

FINAL DETERMINATION
SANTA ROSA ENERGY LLC
Santa Rosa Energy Center
241 MW Cogeneration Facility

The Department distributed a public notice package on October 9, 1998 for the project to construct a natural gas-fired 241 MW Cogeneration facility. The plant proposed site is within the boundaries of the Sterling Fiber, Inc. chemical plant in Pace, Santa Rosa, County. The Public Notice of Intent to Issue was published in the Santa Rosa Press Gazette on October 26, 1998.

No comments were received by the Department from the public or the National Park Service following publication of the Notice. No substantial comments were received from EPA in its letter of November 19, 1998.

Verbal comments regarding the location of the facility in Santa Rosa County and the air quality analysis were received from Department's NE District office. Written comments were received from the applicant, Santa Rosa Energy LLC, by letter dated November 21, 1998. The applicant's comments and the Department's responses follow.

Santa Rosa Energy LLC (SRE) commented only on the draft permit and not on the Technical Evaluation and Preliminary Determination or the Draft Best Available Control Technology (BACT) Determination. The applicant's comments are keyed to the draft permit and to the Specific Conditions contained therein.

1. *<u>Section I - Facility Description:</u> SRE suggests that references to the steam host, Sterling Fibers, be removed since this reference may be viewed as a condition of the permit. In addition, SRE states that should the steam host be acquired or change the nature of its business, this should not affect the permit in any way.*

   The Department recognizes the applicant's concern. This description will not be changed because it is simply information describing the main user of a product (process steam). There are no conditions in the permit requiring that steam be provided to Stirling Fiber nor any that prevent selling steam to other users. If emission offsets had been used from Stirling Fibers, then there would be specific conditions limiting, for example, the amount of steam produced at Stirling Fibers.

2. *<u>Section II - Administrative Requirements, Specific Condition 9:</u> SRE states that the permit does not indicate a time frame under which the application for Title V Permit must be made. SRE requests that this condition be clarified to indicate that application for Title V permit is not required to be submitted until within (12) months of start up.*

   The Department will clarify this condition in accordance with Rule 62-213.420, F.A.C., Permit Applications. Specifically, Rule 62-213.420(1)(a)2. F.A.C., requires filing of a Title V application 180 days after commencing operation rather than 12 months before start up as suggested by the applicant. This rule states: " Except as provided at Rule 62-213.420(1)(a)4., a facility that commences operation as a Title V source after October 25, 1995, or that otherwise becomes subject to the permitting requirements of Chapter 62-213, F.A.C., after October 25, 1995, must file an application for an operation permit under this Chapter ninety days before expiration of the source's construction permit, but not later than 180 days after commencing operation, unless a different application due date is provided at Rule 62-204.800, F.A.C. Therefore, Specific Condition 9 of this Section II is revised as follows:

Application for Title V Permit: An application for a Title V operating permit, pursuant to ~~Chapter~~ Rule 62-213.420 (1) (a) 2. F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northwest District office (DEPNW). [Chapter 62-213, F.A.C.]

3. *Section III - Specific Condition 9: SRE requests that the 1,600 MMBtu per hour heat input be increased to a maximum heat input of 1,780 MMBtu per hour (LHV) corrected to ISO conditions. SRE states that this condition, as written, indicates that the maximum fuel consumption of the turbine is 1,600 MMBTU per hour (LHV) corrected to ISO conditions. SRE adds that while this is the heat input of a new combustion turbine operating at 100% load at ISO conditions, the restriction does not allow for performance degradation of the combustion turbine; and that it is not uncommon for fuel usage to increase more than 10% at various stages of the combustion turbine maintenance cycle.*

   The Department concurs with the applicant and the maximum heat input in this condition is revised to 1,780 MMBtu/hr (LHV) to allow for performance degradation of the combustion turbine

4. *Section III - Specific Condition No. 10: SRE indicates that the natural gas usage in the Duct burner would not exceed 3,280 x 10^6 scf on annual basis. SRE requests that this condition be changed such that the gas usage be limited to 3,280 x 10^6 scf on a twelve (12) month rolling average.*

   The Department concurs with the applicant and modified this condition as requested.

5. *Section III - Specific Condition No. 15: SRE requests that the Department clarify that the emission limits provided for in this condition are based on ISO conditions.*

   The Department modified this condition as requested. In addition, Specific Condition 9 (Turbine Capacity) allows for manufacturer's curves corrected for site conditions or equations for corrections to other ambient conditions.

6. *Section III - Specific Condition No. 20: SRE requests that the Department clarify that the maximum allowable hours of operation are 8760 hours per year.*

   This permit allows continue operation or 8760 hours per year. This condition is revised to reflect this.

7. *Section III - Specific Condition No. 27: Please clarify that any excess emissions that result from startup or shutdown of the unit are not used in calculating the 24-hour block average emissions.*

   This request is already incorporated in Specific Condition 32 which states "Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C." However, all excess emissions shall be reported in accordance with 40 CFR 60.7 as indicated in Specific Condition 29.

Miscellaneous Revisions: The Department revised some language in various permit conditions to clarify the meaning without changing the intent or the stringency of the conditions. The sulfur content in Specific Condition 20 was revised to 2 gr/100 scf since this was the limit used by Santa Rosa for its SO_2 calculations.

CONCLUSION

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

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

PERMITTEE:

Santa Rosa Energy LLC
650 Dundee Road
Northbrook, Illinois 60062

Authorized Representative:

James Shield, Vice-President

DEP File No.	1130168-001-AC
Permit No.	PSD-FL-253
Project	241 MW Cogeneration Plant
SIC No.	4911
Expires:	December 31, 2001

PROJECT AND LOCATION:

Permit for the construction of a natural gas-fired cogeneration plant that will consist of a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent steam host; a 200 foot main stack; and ancillary equipment. The facility is designated as the Santa Rosa Energy Center and will be located within the boundary of the Sterling Fiber Chemical Plant in Pace, Santa Rosa, County.

UTM coordinates are: Zone 16; 488.970 km E and 3,381.350 km N.

STATEMENT OF BASIS:

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

ATTACHED APPENDICES MADE A PART OF THIS PERMIT:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This new major facility is a natural gas-fired 241 megawatt (MW) cogeneration plant that will consist of a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent steam host; a 200 foot main stack; and ancillary equipment. Supplemental firing will be by a duct burner rated at 585 million Btu per hour heat input.

Emissions from the combustion turbine will be controlled by Dry Low NO_X combustors, use of pipeline natural gas and good combustion while emissions from the duct burner arrangement will be controlled by Low NO_X burners, use of pipeline natural gas, and good combustion.

This Project, as presented, is exempt from the applicable requirements of Chapter 403, Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is less than 75 MW. [F.S. Chapter 403.503 (12). Definitions]

The new facility will be located on the site of the steam host, Sterling Fiber, which is a manufacturer of acrylonitrile-based fibers.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 167 Megawatt (nominal) Gas Combustion Turbine-Electrical Generator
002	Steam Generation	One 585 mmBtu/hr Duct Burner in a Supplementary Fired Heat Recovery Steam Generator (and 74 MW Steam Electrical Turbine)
003	Water Cooling	Cooling Tower

SUBSECTION C. REGULATORY CLASSIFICATION

The new facility will be classified as a Major or Title V Source of air pollution because emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) exceed 100 TPY. The new facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions will be greater than 100 TPY for CO and NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) is required for these two pollutants.

SECTION I. FACILITY INFORMATION

Given that the project constitutes a Major Facility for CO or NO_X, emissions greater than 40 TPY of sulfur dioxide (SO_2) or volatile organic compounds (VOC), 25/15 TPY of particulate matter (PM/PM_{10}), etc., also require review per the PSD rules and a BACT determination.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

PERMIT SCHEDULE

- 10/26/98 Notice of Intent published in the Santa Rosa Press Gazette.
- 10/09/98 Distributed Intent to Issue Permit.
- 09/08/98 Application deemed complete.
- 07/08/98 Received Application.

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received July 8, 1998.
- Department letter dated August 3, 1998
- EPA comments received August 11, and November 19, 1998.
- Comments and additional information received from the applicant on September 8, and November 20, 1998.
- Department's Intent to Issue and Draft permit (including Draft BACT Determination and Technical Evaluation and Preliminary Determination) issued October 9, 1998.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northwest District office (DEPNW), 160 Governmental Center, Pensacola, Florida 32501-5794 and phone number 850/595-8300.

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

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

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Permit Approval: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. Permit Extension: *This permit expires on December 31, 2001.* The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

8. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]

SECTION II. ADMINISTRATIVE REQUIREMENTS

9. Application for Title V Permit: An application for a Title V operating permit, pursuant to Rule 62-213.420(1)(a)2. F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northwest District office (DEPNW). [Chapter 62-213, F.A.C.]

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

11. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northwest District office by March 1st of each year.

12. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's Northwest District office.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Unit 001, Power Generation, consisting of a 167 megawatt combustion turbine shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 002, Steam Generation, consisting of a supplementary-fired heat recovery steam generator equipped with a 585 mmBTU/hr Duct Burner shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The modification of 40CFR60, Subpart Da promulgated on September 3, 1998 also applies to this project.

6. ARMS Emission Unit 003, Cooling Tower, is an unregulated emission unit.

7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Northwest District office.

GENERAL OPERATION REQUIREMENTS

8. Fuels: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of the fuel at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,780 million Btu per hour (mmBtu/hr). These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate, shall not exceed 585 mmBtu/hour. Natural gas usage in the Duct Burner shall not exceed 3,280 x 10^6 scf on a twelve (12 month) rolling average. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

12. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Northwest District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

13. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

14. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

15. Maximum allowable hours of operation for the 241 MW Cogeneration Plant are 8760 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine and Low NO_X burners shall be installed in the duct burner arrangement to comply with the NO_X emissions limits listed in Specific Condition 20 and 21. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. The permittee may design the heat recovery steam generator to accommodate installation of selective catalytic reduction or selective non-catalytic reduction or oxidation catalyst technologies and comply with the corresponding NO_X and CO limits listed in Specific Conditions 20, 21 and 22. [Rules 62-212.400 and 62-4.070, F.A.C.]

18. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 26. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

19. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. 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. These limits or their equivalent in terms of lb/hr (ISO conditions) or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions. Each Unit shall be tested alone to comply with the applicable NSPS and as a Combined Unit to comply with the BACT limits as indicated below: [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG and Da), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	VE (%)	SO_2 (gr S/100 scf)	Comments
Combustion Turbine On Duct Burner Off	9 (24-Hr) - DLN 6 (3-Hr) - SCR	9	1.4	10	2 - (fuel)	Natural Gas Good Combustion
Combustion Turbine On Duct Burner On	9.8 (24-Hr) - DLN/Low NO_X 6 (3-Hr) - DLN/SCR 6 (3-Hr) - DLN/SNCR	24	8	10	2 - (fuel)	Natural Gas Good Combustion

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

21. Nitrogen Oxides (NO_X) Emissions:
    - The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on shall not exceed 9.8 ppmvd at 15% O_2 (24-hr block average), and with the combustion turbine operating and the duct burner off shall not exceed 9 ppmvd at 15% O_2 (24-hour block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 106 pounds per hour (lb/hr) with the duct burner on and 64.1 lb/hr with the duct burner off to be demonstrated by initial stack test. [40CFR60 Subpart GG, Subpart Da and Rule 62-212.400, F.A.C.]
    - If selective catalytic or non-catalytic reduction technology is installed, the concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on or off, shall not exceed 6 ppmvd @15% O_2 on a 3-hr block average. Compliance will be determined by the continuous emission monitor (CEMS). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 71 pounds per hour (lb/hr) with the duct burner on and 42.4 lb/hr with the duct burner off to be demonstrated by initial stack test. [40CFR60 Subpart GG, Subpart Da and Rule 62-212.400, F.A.C.]
    - Emissions of NO_X from the duct burner shall not exceed 0.4 lb/MW-hr (gross output). [Rule 62-212.400, F.A.C. and 40CFR60 Subpart Da]
    - 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.
22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither 24 ppm nor 75 lb/hr with the duct burner on and 9 ppm nor 29 lb/hr with the duct burner off to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither 8 ppm nor 14 lb/hr with the duct burner on and 1.4 ppm nor 2.9 lb/hr with the duct burner off to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]
24. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing only pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot). Compliance this requirement with in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 45 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. [40CFR60 Subparts Da and GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

25. Particulate Matter emissions : PM/PM_{10} emissions from the *duct burner* shall not exceed 0.03 lb/mmBTU measured by Method 5 or Method 17. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. [40CFR60 Subpart Da and 62-4.070 F.A.C.].

26. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner and shall not exceed 10 percent opacity from the stack. [40CFR60 Subpart Da, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

27. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from cogeneration plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

28. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

29. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Northwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 and 21. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1997 version)].

COMPLIANCE DETERMINATION

30. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

31. Initial (I) performance tests shall be performed by the deadlines in condition 30. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of SCR or SNCR (if required). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
   - EPA Reference Method 5 or Method 17, Determination of Particulate Emissions From Stationary Sources (I, at stack only).
   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG, Da. NO_X BACT limits compliance by CEMs (24-hr average or 3-hr average if SCR/SNCR is required).
   - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

32. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 29. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

33. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when

determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

34. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75.

35. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

36. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

37. Test Notification: The DEP's Northwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

38. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

39. Test Results: Compliance test results shall be submitted to the DEP's Northwest District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

40. Records: All measurements, records, and other data required to be maintained by Santa Rosa Energy Center shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

41. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

42. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Condition No 20 and 21, shall be reported to the DEP Northwest District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1997 version)].

43. CEMS for reporting excess emissions: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

44. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62 .

45. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

47. Subpart Da Monitoring: The permittee shall comply with the applicable monitoring requirements of 40 CFR60, Subpart Da.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Santa Rosa Energy Center
Permit No. 1130168-001-AC (PSD-FL-253)
Pace, Santa Rosa County, Florida

BACKGROUND

The applicant, Santa Rosa Energy LLC (SREL), proposes to install a combined-cycle cogeneration plant at the Sterling Fibers Facility located at 5005 Sterling Way, Pace, Santa Rosa County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 167 MW, General Electric 7FA combustion turbine-electrical generator, fired exclusively with pipeline natural gas. The project includes a supplementary-fired heat recovery steam generator (HRSG) and a steam turbine-electrical generator to produce an additional 74 MW of electrical power. A portion of the steam produced will be at the host Sterling Fibers Plant. The unit will exhaust through a 200 foot stack. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated October 7, 1998, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on July 8, 1998 and included a proposed BACT proposal prepared by the applicant's consultant, Roy F. Weston. Additional information amending the application and BACT proposal was received on September 8.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E., and Teresa Heron, Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas Combustion Controls	0.0051 lb/MMBtu (CT) 0.0080 lb/MMBtu (DB)
Volatile Organic Compounds	As Above	1.4 ppm (CT) 0.0190 lb/MMBtu (DB)
Carbon Monoxide	As Above	9 ppm (CT) 0.080 lb/MMBtu (DB)
Nitrogen Oxides	Dry Low NO_X Combustors Dry Low NO_X Burners	9 ppm @ 15% O_2 (CT) 0.08 lb/mmBtu (DB)

According to the revised application, the units, would emit approximately 402 tons per year (TPY) of NO_X, 260 TPY of CO, 45 TPY of VOC, 7 TPY of SO_2, and 55 TPY of PM/PM_{10}.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by SERL is consistent with Subpart GG NSPS which allows NO_X emissions of approximately 110 ppm for the high efficiency unit to be purchased by the Santa Rosa Energy LLC.

The fired duct burner required for supplementary gas-firing of the HRSG is subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The BACT proposed by SERL is consistent with the key historically applicable NSPS requirement of 0.20 pounds of NO_X per million Btu heat input (lb NO_X/mmBtu). It is well below the revised Subpart Da output-based limit of 1.6 lb NO_X/MW-hr promulgated on September 3, 1998.

No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on recent limitations set by EPA and the States for comparable stationary gas turbine.

Project Location	Power Output and Duty	NO_X Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Lakeland, **FL**	350 MW CC CON	9/9/7.5 - NG 42/15/15 - No. 2 FO	DLN/HSCR/SCR WI/HSCR/SCR	230 MW WH 501G CT Initially 250 MW simple cycle and 25 ppm NO_X limit on gas
Mid-GA Cogen	308 MW CC CON	9 - NG 20 - No. 2 FO	DLN & SCR	2x119 MW WH 501D5A CTs
Fort Myers, **FL**	1500 MW CC CON	9 - NG	DLN	6x170 MW **GE MS 7241** CTs Draft Permit, Non-BACT
Tiger Bay, **FL**	270 MW CC CON	15/10 - NG 42 - No. 2 FO	DLN &/or SCR WI	184 MW GE MS7001**FA** CT DLN/15 ppm or SCR/10 ppm
Hines Polk, **FL**	485 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW WH 501**FC** CTs Canceled GE CTs
Tallahassee, **FL**	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231**FA** CT DLN guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC CON	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW WH 501**F** CTs
Sithe/IPP, NY	1012 MW CC CON	4.5 - NG	DLN & SCR	4 x160 MW GE **7FA** CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW GE **7FA** CTs
Barry, AL	800 MW CC CON	3.5 - NG (CT/DB)	DLN & SCR	3x170 MW GE **7FA** CTs

CC = Combined Cycle
DB = Duct Burner
NG = Natural Gas
CT = Combustion Turbine
CON = Continuous
HSCR = Hot SCR
FO = Fuel Oil
ISO = 59°F
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
LPG = Liquefied Propane Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari
ppm = parts per million

Factors in Common with Santa Rosa Energy LLC Project are bolded.

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Mid-GA Cogen,	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
Fort Myers, FL	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Tiger Bay, FL	0.045 lb/mmBtu-NG 0.053 lb/mmBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Barry, AL	0.034 lb/mmBtu - NG/CT 0.057 lb/mmBtu - CT/DB	0.015 lb/mmBtu After CT and DB	0.011 lb/mmBtu - CT/DB 10% Opacity	Gas Only Good Combustion

The following table is a sample of information on recent NO_X limitation by EPA and the States for combined cycle and cogeneration projects incorporating supplementary-firing in heat recovery steam generators.

Project Location	Duct Burner Rated Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu or ppm)	Technology	Comments
Plant Berry, AL	159	0.018 mmBtu/hr	DLN, SCR	3x170 MW GE 7FA CTs 3 Duct Burners
Saranac Energy, NY	553	0.08 lb/mmBtu	SCR	2 GE 7EA CTs with DBs Permit issued 1992
Bermuda HEL, VA	197	9 ppm	Steam Injection, SCR	1175 mmBtu/hr CT (1992)
Bear Island Paper, VA	129	9 ppm	SCR	474 mmBtu/hr CT (1992)
Pilgrim Energy, NY	214	4.5 ppm (CT) 0.012 lb/mmBtu (DB)	Steam Injection, SCR Low NO_X Burner, SCR	2 WH 501D5 CTs 2 Duct Burners
Selkirk Cogen, NY	206	9 ppm (CT) 0.018 lb/mmBtu (DB)	Low NO_X Burner, SCR	1173 mmBtu/hr CT
Grays Ferry, PA	366	9 ppm (CT) 0.09 lb/mmBtu (DB)	DLN Low NO_X Burner	WH 501D5A CT with DB DLN Failed, SCR Required

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Letter from EPA Region IV dated August 11, 1998
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

COMBUSTION TURBINE AND DUCT BURNER CONTROL TECHNOLOGIES:

The applicant presented an analyses of the different available control technologies for all of the pollutants subject to PSD review and a BACT determination. The applicability of these measures is best understood in conduction with the mechanisms by the pollutants are generated.

Nitrogen Oxides Formation

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

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

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in lean, near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the SREL project because only natural gas will be used.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

The potential for NO_X emissions from gas-fired duct burners is lower than from gas turbines because of the lower temperature and pressure. In a supplementary-fired duct burner, the gas to the HRSG is raised from approximately 1100 to less than 1800 °F. Thermal NO_X formation essentially ceases at temperatures below 2000 °F.[1] Since the fuel contains virtually no nitrogen, there is little potential for fuel NO_X formation either.

NO_X Control Techniques

Combustion Controls

The excess air in lean combustion, cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

The emission characteristics of General Electric's DLN 2 combustors are given in Figure 2. NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity. GE has since further upgraded its combustors and this description is not precise for its more advanced DLN-2.6.

Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the SREL project are shown in Figure 3. The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle to achieve 9 ppm of NO_X and 9 ppm of CO at somewhat less than 50 percent load. Presumably the emission characteristics of the DLN-2.6 are similar are similar to the DLN 2, except that the combustor emits NO_X at concentrations of 9 ppm (instead of the 25 ppm shown in Figure 2) at loads between 50 and 100 percent. Because of the "totally pre-mixed" design, emissions at less than 50 percent load are probably also lower for the DLN 2.6 than the DLN-2.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, results in a lower achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to the steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle), such as the F class. As in the case of wet injection, higher CO and hydrocarbon emissions can occur as a result of employing combustion controls to minimize NO_X.

Figure 5 is a diagram of a typical in-line duct burner configuration and individual burner manufactured by Coen, one of the potential providers of this equipment. The unit will reside within the duct between the combustion turbine outlet and the HRSG. The oxygen-rich, hot turbine exhaust is used to burn natural gas introduced through the burner arrangement. In contrast to the pre-mixing that can be accomplished in the combustion turbine, not much (other than design optimization) can be done regarding the manner by which the very large volume of hot combustion air and the fuel are mixed prior to combustion. Basically the burners are described as Low NO_X burners.

There have been reports of lower emissions (on a lb/mmBtu or ppm basis rather than on a lb/hr basis) with the duct burners on. It has been theorized that the results are "suspect" and may have been cause by the "inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.".[2] It has also been theorized that transformations between NO and NO_2, interfere with the test method.[3] As previously mentioned, since the duct burner operates at a lower temperature and pressure than the gas turbine, it is possible that concentrations may actually be lower with the duct burner on.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas. As of early 1992, over 100 gas turbine installations already used SCR in the United States. No combustion turbines in Florida employ SCR. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

In a manner analogous to balancing control of NO_X from the combustor with emissions of CO and hydrocarbon, similar balancing is required when controlling NO_X by SCR. Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit BACT limits as low as 3.5 ppm NO_X have been specified using SCR for an F Class project (with small in-line duct burners) in Alabama and proposed for another F Class project in Mississippi.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. A supplementary-fired unit (such as the SREL project) is defined as an HRSG fired to an average temperature not exceeding about 1800 °F. The 585 mmBtu/hr duct burner described by SREL will achieve temperatures close to this value. Although no SNCR applications are known, the technology appears to be feasible and possibly less complicated than SCR.

Carbon Monoxide (CO) Control

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 Berkshire, Massachusetts facility, 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppm at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the CT value of 9 ppm baseload proposed by SREL appears relatively low, but consistent with the capabilities of DLN-2.6 technology as discussed above. This proposed limits are achievable through good combustion practice. When simultaneously operating the combustion turbine and the duct burner, CO concentrations emissions will be less than 24 ppm which is within the range of limits set for combustion turbines operating alone. Annual emissions of CO are expected to be less than 260 tons per year (combustion turbine and duct burner).

Volatile Organic Compound (VOC) Control

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC for both the turbine and the duct burner. The CT proposed limit is 1.4 ppm . According to GE, even lower VOC emissions were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[4] VOC concentrations will be less than 8 ppm for simultaneous operation of the combustion turbine and duct burner.

Particulate Matter (PM/PM_{10}) Control

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas will be the only fuels fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. This has been chosen as BACT by the applicant, the Department concurs. Annual emissions of PM/PM_{10} are expected to be less than 55 tons per year (combustion turbine and duct burner).

Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10}. The.drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required.

BACKGROUND ON SELECTED GAS TURBINE AND DUCT BURNER

SERL plans to the purchase a 167 MW (nominal) General Electric 7FA combined cycle gas turbine with a supplementary-fired heat recovery steam generator (HRSG) equipped with a duct burner and a steam turbine-electrical generator to produce an additional 74 MW (nominal) of electrical power and process steam.

The 585 mmBtu/hr duct burner will be manufactured by Coen or equivalent and will be a low NO_X design. For reference, the heat rate of a combustion turbine with a 600 mmBtu/hr supplementary-fired duct burner used to make only electrical power is 4,350 Btu/KW-hr.[5] In cogeneration mode, if only 50 percent of the process steam generated is considered, the heat rate is even lower. This compares with the presumed heat rate of 10,667 Btu/KW-hr in the recently revised NSPS Subpart Da.[6]

The first commercial GE 7F Class unit was installed at the Virginia Power Chesterfield Station in 1990.[7] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppm These actually achieve less 25 ppm of NO_X and 15 ppm of CO. The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppm of NO_X, the City obtained a performance guarantee from GE of 9 ppm.[10] FPL also obtained a guarantee of 9 ppm for six GE 7241FA turbines to be installed at the Fort Myers Repowering project. These limits were incorporated in the draft permit issued for the project.[11]

General Electric, other manufacturers, and their customers are relying on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[12]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7FA units met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.[13] Although the permitted limit is 15 ppm, GE has already achieved emission levels of approximately 6 ppm on gas at a dual-fuel 7EA (120 MW combined cycle) unit at Cane Island Power Park in Kissimmee, FL.[14] The Cane Island unit is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line and performance guarantees less than 9 ppm can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[15]

The 9 ppm NO_X limit on natural gas during baseload requested by SREL is typical compared with recent BACT determinations for F Class units, such as those previously listed.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V Control System, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V Control System.[16]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the SERL project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 and 21.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	1.4 ppm (CT on, DB off) 8 ppm (CT and DB on))
CO	As Above	9 ppm (CT on, DB off) 24 ppm (CT and DB on)
NO_X (CT on, DB off)	DLN or SCR	9 ppm or 6 ppm
NO_X (CT and DB on)	DLN and Low NO_X, or SNCR, or SCR	9.8 ppm, or 6 ppm, or 6 ppm DB limited to 0.4 lb/MW-hr

RATIONALE FOR DEPARTMENT'S DETERMINATION

- SERL can obtain a guarantee from GE for DLN-2.6 combustors which have been demonstrated to meet all of the above limits on 7FA Class gas turbine with the duct burner off.
- The turbine emission limits with the duct burner off comply with the NSPS and are less than or equal to recent Department BACT determinations applicable to new units at start-up.
- VOC emissions of 1.4 ppm from the combustion turbine proposed by SERL are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels

with the DLN-2.6 combustors while firing natural gas. The limit of 8 ppm with the duct burner on is also quite low.

- The duct burner used for supplementary firing will comply with the NSPS (Subpart Da). It will cause sligthly higher NO_X concentrations than permitted for the combustion turbine alone.
- If a different combustion turbine is selected or if the NO_X limits cannot be met with Low NO_X technology with the duct burner on, SERL must install either SNCR or SCR technology and meet correspondingly lower emission limits achievable by the latter technologies.
- The levelized costs of NO_X reduction to 3.5 - 6 ppm by conventional SCR installed in the HRSG were estimated by SERL as $4,660 - 5,247 per ton of NO_X removed after initial control by DLN to 9 ppm. The Department's estimates the levelized costs at $2,500 per ton of NO_X removed starting with DLN combustion control to 25 ppm. This figure does not reflect a possible credit for savings by purchasing the less expensive line of combustors such as the GE DLN-1 or DLN-2 in lieu of the DLN 2.6 combustors. Neither the Department nor the SERL estimates reflect the cost-effectiveness of duct burner-generated NO_X removal.
- If the combined unit can meet applicable limits by DLN with the duct burner off but not with the duct burner on, SNCR can be utilized when the duct burner is on. SNCR is less expensive and more cost-effective than SCR. It can be turned off when the duct burner is off since the proper operating temperature range will not exist under that mode.
- SCR and SNCR cause environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. At equal emission rates, DLN technology is a better control strategy than SCR or SNCR. At higher emission rates, DLN can still be justified as BACT given the negative effects of SCR described above. Accordingly, the Department has set a range of emission limits and control methods based on the turbine and duct burner combustion technologies chosen by SREL.
- The Department's overall BACT determination is equivalent to approximately 0.16 lb/MW-hr by DLN/Low NO_X or 0.10 lb/MW-hr by SCR or SNCR. For reference, NSPS promulgated on September 3, 1998 requires that new Da units meet a limit of 1.6 lb/MW-hr.
- The Department considers a limit of 9.8 ppm (DLN and Low NO_X) or 6 ppm (SCR or SNCR) as BACT for this cogeneration facility. In addition the contribution of the duct burner to overall emissions cannot exceed 0.4 lb/MW-hr.
- The CO concentrations of 9 ppm are very low with the duct burner off. With the duct burner on, they will be less than 24 ppm which is within the range of recent Department BACT determinations for combustion turbines alone. The Department will set CO limits achievable by good combustion equal to 9 ppm for the combustion turbine and 24 ppm when the duct burner is on. For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppm on gas while the limit for the FPL Fort Myers project is 12 ppm. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- SREL evaluated the use of an oxidation catalyst designed for 85 percent reduction and having a three year catalyst life. The oxidation catalyst control system was estimated by SREL to increase

the total capital cost of the project by $1,462,846, with an annualized cost of $548,257 per year. SREL estimated levelized costs for CO catalyst control at about $2,481 per ton to control CO emissions to 39 TPY (from 260 TPY).

- The VOC emission concentration of 1.4 ppm proposed by SREL is at the lower end of values determined as BACT for the combustion turbine alone. Good Combustion is sufficient to achieve these low levels. With the duct burenr on, the levels are still relatively low except at very high operating rates.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, and the FPL Fort Myers projects in Florida as well as the Barry, Alabama project.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 29 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: For 1 hour following a shutdown less than or equal to 8 hours.
Warm Start: For 2 hours following a shutdown between 8 and 48 hours.
Cold Start: For 4 hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the unit has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[17]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

12/2/98
Date:

Approved By:

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

12-4-98
Date:

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1 Report. EPA. "Summary Report - Control of NO_X Emissions by Reburning." Document EPA/625/R-96/001. February, 1996.
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3 Verbal Communication. Harley, M., Florida DEP, and Linero, A. A., Florida DEP. September 18, 1998. Custom Fuel Monitoring and NSPS Da and Db Applicability.
4 Telecon. Vandervort, C., GE, and Linero, A. A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."
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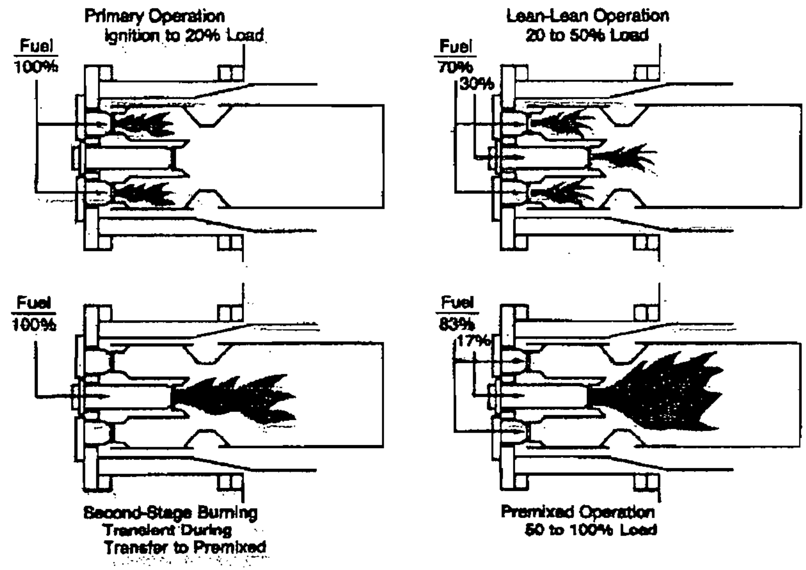
15 Telecon. Schorr, M., GE, and Linero, A. A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.
16 Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."
17 General Electric. Combined Cycle Startup Curves. June 19, 1998.



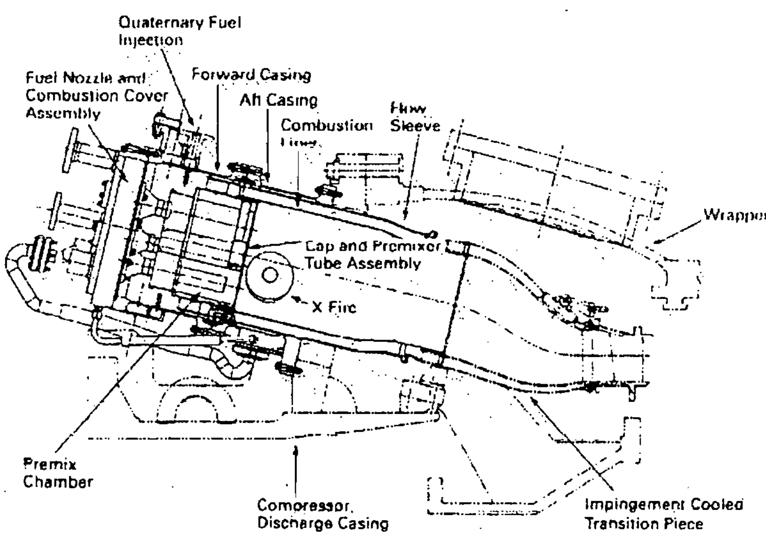


Figure 1 - Dry Low NOX Operating Modes - DLN-1

Cross Section of DLN-2.0

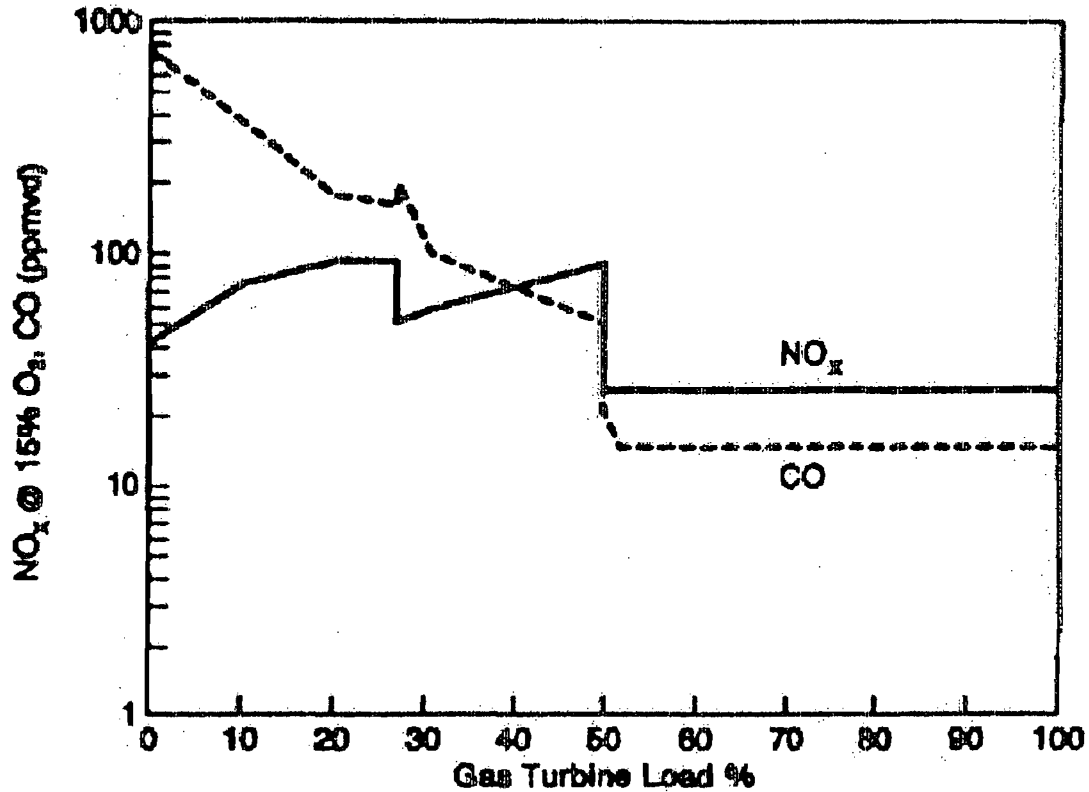


Figure 2 - Emissions Performance Curves for GE DLN-2 Combustors

Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

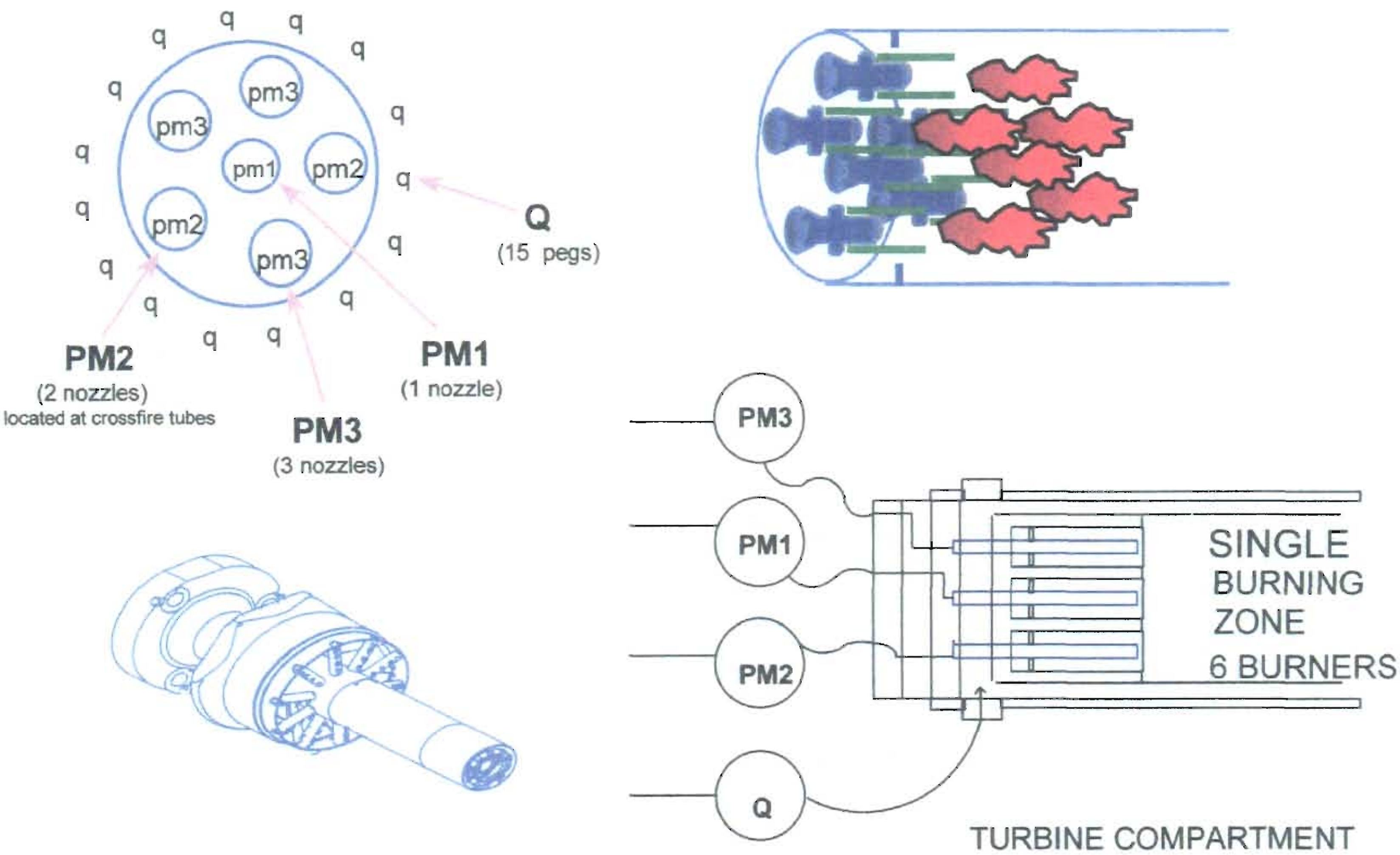


Figure 3 - GE DLN-2.6 Combustor and Nozzle Arrangement

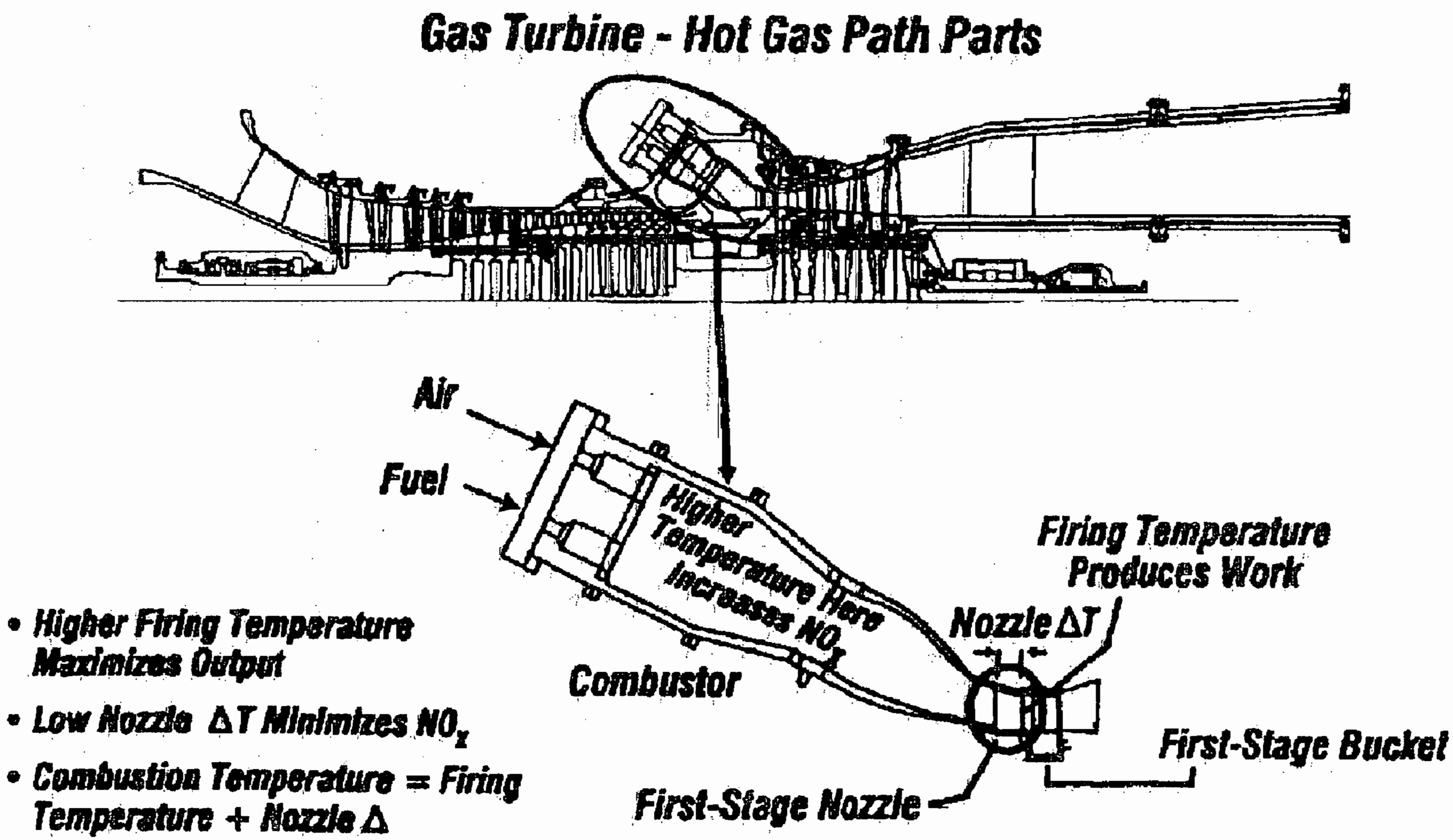


Figure 4 - Relation Between Flame Temperature and Firing Temperature

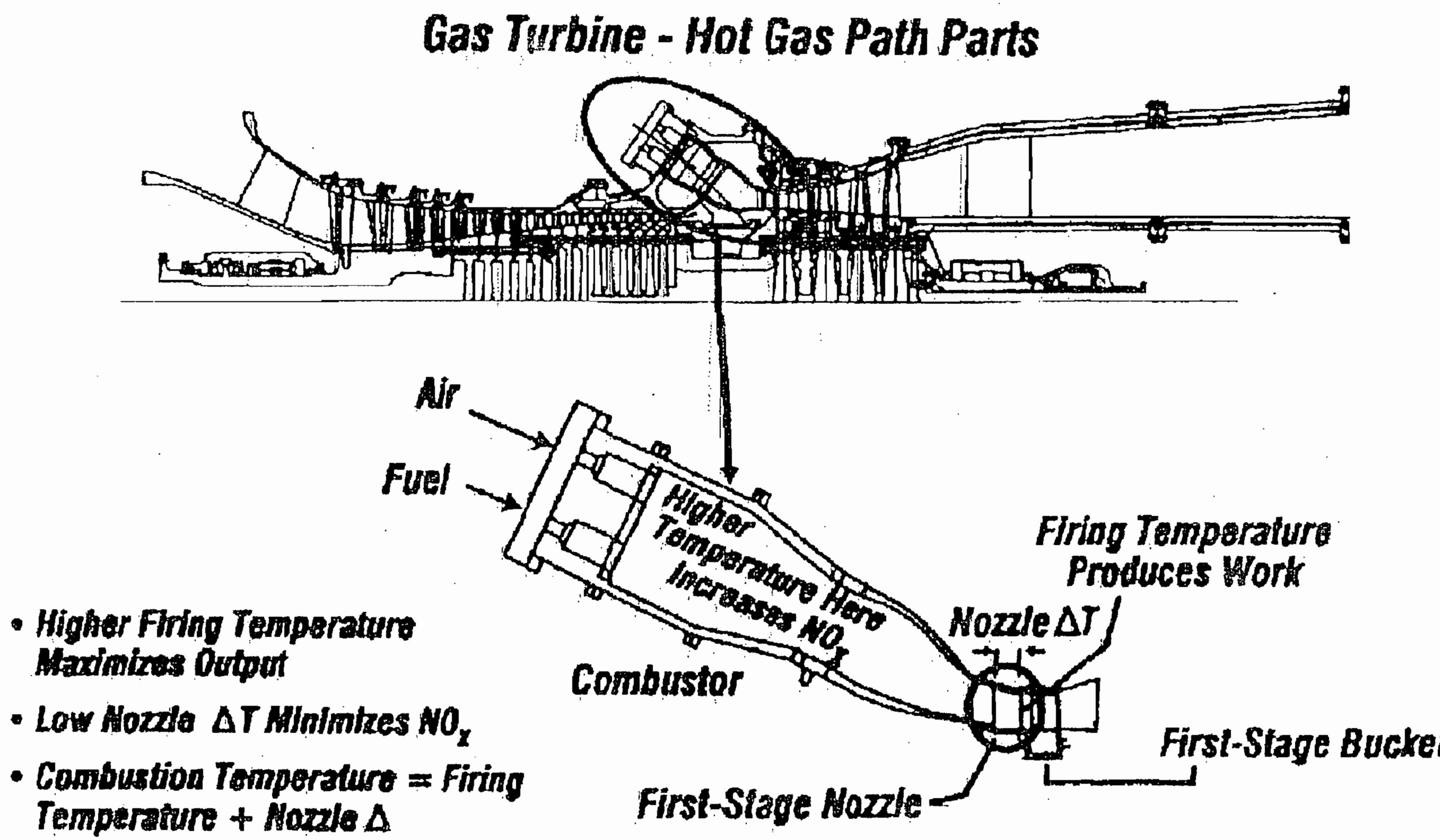
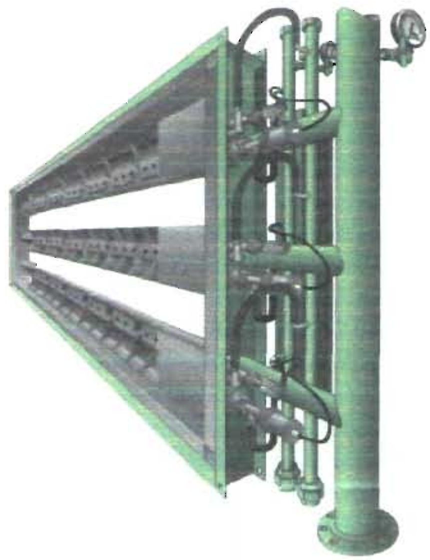
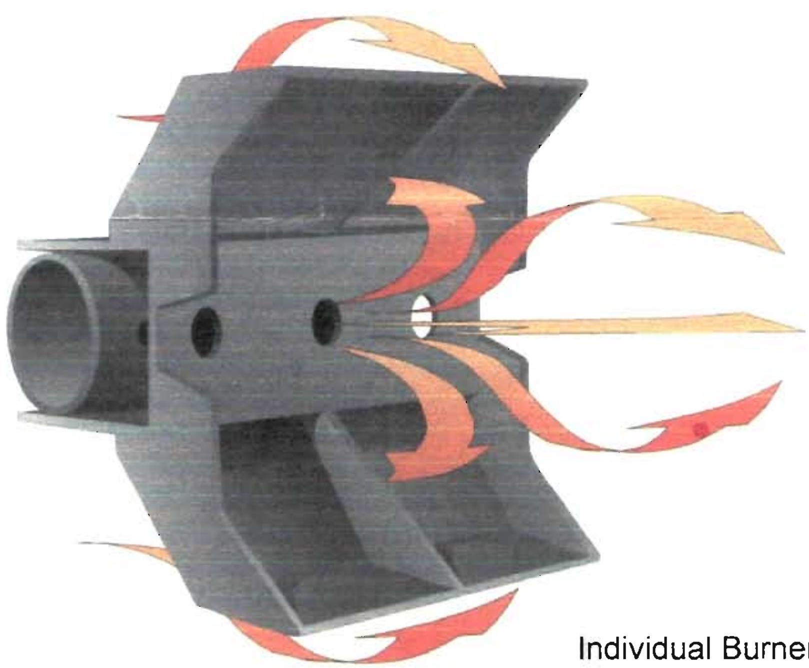


Figure 4 - Relation Between Flame Temperature and Firing Temperature

Burner Arrangment





Individual Burner

Figure 5 - Coen In-Line Gas-Fired Duct Burner

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Florida Department of
Environmental Protection

Memorandum

TO: Howard L. Rhodes

THRU: C. H. Fancy *aaf for CHF 12/2*

FROM: A. A. Linero *AAL*

DATE: December 2, 1998

SUBJECT: Santa Rosa Energy Center 241 MW Cogeneration Project
DEP File No. 1130168-001-AC

KRM

Attached is the final permit package including the BACT determination for the Santa Rosa Energy Center (SREC) Cogeneration Project. The facility will be located at the site of Sterling Fibers (formerly Cytec) who will serve as the steam host.

The basic unit is a nominal 167 megawatt General Electric MS7241FA gas-fired combustion turbine-generator. The project includes a supplementary-fired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 74 MW via a steam-driven electrical generator as well as additional steam for use by Sterling Fibers.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of carbon monoxide (CO) will be controlled to 9 ppm, while emissions of volatile organic compounds (VOC) will be less than 1.4 ppm. Emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the switch to inherently clean pipeline quality natural gas. There will be no provisions for firing fuel oil.

A very large duct burner is proposed. While it is in operation, the combined limit for the gas turbine and duct burner will be 9.8 ppm for NO_X. If the duct burner manufacturer is unable to meet these levels by Low NO_X, they can be achieved in a cost-effective manner by SCR or SNCR. In this case a limit of 6 ppm will apply.

Santa Rosa Energy reviewed and agreed with the BACT. EPA reviewed it and was satisfied with the single digit limits. The impacts in the PSD Class I (St. Marks and) and Class II areas are not significant. I recommend your approval of the attached Permit and BACT Determination.

AAL/th

Attachments

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:
James Shield, VP
Santa Rosa Energy
650 Dundee Rd - Suite 150
Northbrook, IL
60062

4a. Article Number
Z 333 612 566

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

7. Date of Delivery
12-7-98

5. Received By: (*Print Name*)

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

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

PS Form 3811, December 1994 102595-97-B-0179 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 612 566

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

Sent to James Shield	
Street & Number Santa Rosa	
Post Office, State, & ZIP Code Northbrook, IL	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 12-4-98 1130168-001-AC P50-F1-253	

PS Form 3800, April 1995

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

NOV 1 9 1998

4APT-ARB

RECEIVED
NOV 23 1998
BUREAU OF
AIR REGULATION

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

SUBJ: PSD Permit from Santa Rosa Energy Center, Sterling Fibers Manufacturing Facility, Pace, Florida (PSD-FL-253)

Dear Mr. Fancy:

Thank you for your letter of October 9, 1998, submitting a preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility. The draft permit is for the installation of a combustion turbine combined cycle cogeneration facility which will be located within the Sterling Fibers Inc. plant boundary. The facility will provide steam and electricity to Sterling Fibers and electricity to the electric utility grid. The proposed cogeneration facility will consist of a 167 MW combustion turbine (CT) generator, a heat recovery steam generator (HRSG) equipped with a 585 mmBtu/hr duct burner, a 74 MW (gross output) steam turbine generator, and associated auxiliary equipment. The combustion turbine and duct burner will only fire natural gas. The CT will be a General Electric (GE) Frame 7F design or equivalent.

The proposed best available control technology (BACT) for NO_x emissions consists of the use of dry low NO_x (DLN) combustors on the CT and the use of low NO_x burners in the duct burner. The proposed NO_x emission limit is 9.8 ppmvd at 15% O_2 (106 lb/hr), with the CT operating and the duct burner on. The proposed NO_x emission limit is 9 ppmvd at 15% O_2 (64.1 lb/hr), with the CT operating and the duct burner turned off. If a different CT is selected or if the NO_x limits cannot be met with low NO_x technology with the duct burner on, a selective catalytic reduction (SCR) or a selective non-catalytic reduction (SNCR) system must be installed to meet an emission limit of 6 ppmvd at 15% O_2. If the combined unit can meet applicable limits by using DLN on the CT with the duct burner off but not with the duct burner on, SNCR may be utilized with the duct burner on. The proposed BACT emission limits for PM/PM_{10}, CO, and volatile organic compounds (VOCs) are based on the use of good combustion practices and clean burning fuels. Based on our review of the preliminary determination and draft permit, we do not have any adverse comments.

As indicated in the draft permit, the regulations at 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines will be applicable to the new combustion turbine. 40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units will apply to the duct burner.

Thank you for the opportunity to review and comment on the draft permit and supporting information. If you have any questions, please contact Keith Goff of my staff at (404)562-9137.

Sincerely,

Paul Wagner for

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

CC: NWD
J. Heron, BAR
NPS

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 9, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. Douglas Neeley, Chief
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
Santa Rosa Energy Center Cogeneration Project
DEP File 1130168-001-AC

Dear Mr. Neeley:

Enclosed is a copy of the Department's Intent to Issue a permit to construct the Santa Rosa Energy Center. It will be a natural gas-fired cogeneration facility consisting of: a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent Sterling Fibers facility. Supplementary firing will be accomplished by a 585 million Btu per hour gas-fired duct burner.

The project is subject to the State's approved SIP for PSD review and is not subject to Florida's Power Plant Siting procedure because it will generate less than 75 MW of steam electricity.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the enclosed letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which has a maximum SO_2 emission rate of 0.0006 lb/MMBtu (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 0.003 % sulfur. No fuel oil will be used. The requirement has been incorporated into the enclosed draft permit as Specific Condition 45 and reads as follows:

Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

Please comment on Specific Condition 32 which allows the use of the acid rain NO_X CEMS for demonstrating compliance as well as reporting excess emissions. The Subpart GG requirements for the water-to-fuel monitoring system do not apply because only combustion controls will be employed. Typically NO_X emissions will be less than 10 ppmvd @15% O_2 which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedule and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Teresa Heron at 850/921-9529.

Sincerely,

10/9

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

AAL/aal

Enclosures

SANTA ROSA *ENERGY* LLC

650 Dundee Road, Suite 150
Northbrook, Illinois 60062
Telephone (847)559-9800
Facsimile (847)559-1805

October 27, 1998
Letter No. 14

FEDERAL EXPRESS

RECEIVED

OCT 29 1998

BUREAU OF
AIR REGULATION

Mr. A.A. Linero
Administrator, New Source Review Section
Division of Air Resources Management
State of Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road., MS# 5505
Tallahassee, FL 32399-2400

Subject: DEP File No. 1130003-005AC (PSD-FL-253)
Santa Rosa Energy Center

Dear Mr. Linero:

Santa Rosa Energy LLC is pleased to provide the enclosed newspaper affidavit as proof that the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT"was published in the legal section of the *Santa Rosa Press Gazette* on October 26, 1998.

Should you have any questions or require further information, please contact me at (847)559-9800 extension 325.

Sincerely,

SANTA ROSA ENERGY LLC

Craig Carson

CRC:ag

Enclosure

cc: J. Shield
J. Lay (Sterling Fibers
S. Alderman (Katz, Kutter)
M. Carey (Weston)

cc: J. Heron, BAR
NWD
EPA
NPS

File: SRO - ENV

The Santa Rosa
PRESS GAZETTE
PUBLISHED WEEKLY
Milton, Santa Rosa County, Florida

STATE OF FLORIDA

County of Santa Rosa

Before the undersigned authority personally appeared
Susan Holley

who on oath says that he is Cashier
of the Press Gazette, a weekly newspaper published at Milton in Santa Rosa County, Florida; that the attached copy of advertisement being a Public Notice
in the matter of Intent to Issue Air Construction Permit

in the ________ court,
was published in said newspaper in the issues of:
October 26 A.D., 1998
A.D., 19___
A.D., 19___
A.D., 19___
A.D., 19___
A.D., 19___

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

I (SWEAR) (AFFIRM) that the above information is true and correct to the best of my knowledge.

Susan Holley
(Signature of Applicant)

Sworn to and subscribed before me this 26 day of October 1998.

Carolyn V. Barnes
(Signature of Notary Public-State of Florida)

(Print, Type or Stamp Commissioned Name of Notary Public)

CAROLYN V. BARNES
MY COMMISSION # CC 402905
EXPIRES: November 12, 1998
Bonded Thru Notary Public Underwriters

Personally known ✓ OR Produced Identification ________
Type of Identification Produced: ________

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Santa Rosa Energy Center
Santa Rosa Energy LLC

Permit No. 1130168-001-AC (PSD-FL-253)
Pace, Santa Rosa County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Santa Rosa Energy LLC (SREL). The permit is to construct a natural gas-fired cogeneration facility consisting of: a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent Sterling Fibers facility; a 200 foot main stack; and ancillary equipment. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM10), nitrogen oxides (NOx), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are Santa Rosa Energy LLC, 650 Dundee Road, Northbrook, Illinois 60062.

The cogeneration facility will be located within the boundaries of the existing Sterling Fiber chemical plant in Pace, Santa Rosa County. Nitrogen oxides emissions will be controlled by Dry Low NOx(DLN) gas turbine combustors and Low NOx duct burners capable of achieving overall emissions of 9.8 parts per million by volume at 15 percent oxygen (ppmvd@15%O2) with both the combustion turbine and duct burner operating simultaneously. Lower emission limits will apply if SREL choose selective catalytic reduction or selective non-catalytic reduction in lieu of or in conjunction with DLN technology. SO2 and PM/PM10 will be limited by use of natural gas. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum potential annual emissions in tons per year based on the original application are summarized below. NOx emissions will be lower as a result of the Department's BACT determination. Emission increases will also be lower because of decreased use by Sterling Fibers of existing and less efficient boilers.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM10	55	25/15
SO2	7	40
NOx	402	40
VOC	45	40
CO	260	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. The effects of the project are considered to be minimal.

The department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

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

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

Department Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8300
Fax: 850/595-4417

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

102698
102698
1021980001

Z 333 612 525

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

Sent to James Shield	
Street & Number Santa Rosa Energy	
Post Office, State, & ZIP Code Northbrook IL	
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 10-9-98 113D168-001-AC PSO-F1-253	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

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

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. James Shield, VP
Santa Rosa Energy
650 Dundee Rd - Suite 150
Northbrook, IL 60062

4a. Article Number
Z 333 612 525

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

7. Date of Delivery
10/13/98

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

Thank you for using Return Receipt Service.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

October 9, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James Shield
Vice-President
Santa Rosa Energy LLC
650 Dundee Road, Suite 150
Northbrook, Illinois 60062

Re: DEP File No. 1130168-001-AC (PSD-FL-253)
Santa Rosa Energy Center - Cogeneration Plant

Dear Mr. Shields:

Enclosed is one copy of the Draft Air Construction Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the referenced project at the Santa Rosa Energy LLC, 5005 Sterling Way, Pace, Santa Rosa County. The Department's Intent to Issue Air Construction Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" must be published in the legal section of a newspaper of general circulation in Santa Rosa County. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please call Ms. Teresa Heron at 850/921-9529 or Mr. Linero at (850)921-9523.

Sincerely,

A A Linero 10/9

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

CHF/aal

Enclosures

In the Matter of an
Application for Permit by:

Mr. James Shield, Vice-President
Santa Rosa Energy LLC
650 Dundee Road, Suite 150
Northbrook, Illinois 60062

DEP File No. 1130168-001-AC
DRAFT Permit No. PSD-FL-253
241 MW Cogeneration Plant
Santa Rosa County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

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

The applicant, Santa Rosa Energy LLC, applied on July 8, 1998 to the Department for an air construction permit to construct a natural gas-fired cogeneration facility consisting of: a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent Sterling Fibers facility; a 200 foot main stack; and ancillary equipment. The plant will be located within the boundaries of the Sterling Fiber, Inc. chemical plant in Pace, Santa Rosa, County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit, including a review for the Prevention of Significant Deterioration and a determination of Best Available Control Technology for the control of nitrogen oxides, carbon monoxide, particulate matter, and volatile organic compounds, is required to conduct the work.

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

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

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

The Department will accept written comments concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-9-98 to the person(s) listed:

Mr. James Shield, SRELLC *
Mr. Craig Carson, SRELLC
Mr. Mark Cramer, P.E., R. F. Weston
Mr. Ed Middleswart, DEP-NWD
Mr. Doug Neely, EPA
Mr. John Bunyak, NPS

Clerk Stamp

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

Kuri Tober 10-9-98
(Clerk) (Date)

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Santa Rosa Energy Center
Santa Rosa Energy LLC

Permit No. 1130168-001-AC (PSD-FL-253)
Pace, Santa Rosa County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Santa Rosa Energy LLC (SREL). The permit is to construct a natural gas-fired cogeneration facility consisting of: a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent Sterling Fibers facility; a 200 foot main stack; and ancillary equipment. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are Santa Rosa Energy LLC, 650 Dundee Road, Northbrook, Illinois 60062.

The cogeneration facility will be located within the boundaries of the existing Sterling Fiber chemical plant in Pace, Santa Rosa County. Nitrogen oxides emissions will be controlled by Dry Low NO_X (DLN) gas turbine combustors and Low NO_X duct burners capable of achieving overall emissions of 9.8 parts per million by volume at 15 percent oxygen (ppmvd@15% O_2) with both the combustion turbine and duct burner operating simultaneously. Lower emission limits will apply if SREL chooses selective catalytic reduction or selective non-catalytic reduction in lieu of or in conjunction with DLN technology. SO_2 and PM/PM_{10} will be limited by use of natural gas. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum potential annual emissions in tons per year based on the original application are summarized below. NO_X emissions will be lower as a result of the Department's BACT determination. Emissions increases will also be lower because of decreased use by Sterling Fibers of existing and less efficient boilers.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	55	25/15
SO_2	7	40
NO_X	402	40
VOC	45	40
CO	260	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. The effects of the project are considered to be minimal.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

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

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

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

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

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

Department Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8300
Fax: 850/595-4417

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

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Santa Rosa Energy LLC

Santa Rosa Energy Center
241 Megawatt Cogeneration Plant
Pace, Santa Rosa County

DEP File No. 1130168-001-AC
PSD-FL-253

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

October 9, 1998

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Santa Rosa Energy LLC (SREL)
5005 Sterling Way
Pace, Florida 32571

Authorized Representative: James Shield, Vice-President

1.2 Reviewing and Process Schedule

07-08 98:	Date of Receipt of Application
08-03-98:	DEP Incompleteness Letter
09-08-98:	Received Santa Rosa Response to Incompleteness Letter
10-09-98:	Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

The Santa Rosa Energy Center (SREC) will be located within the boundaries of the Sterling Fibers' chemical complex in Pace, Santa Rosa, County. This site is approximately 200 kilometers from the Bradwell Bay National Wilderness Area, 210 kilometers from the St. Marks National Wilderness Area and 175 kilometers from the Breton National Wilderness Area in Louisiana, all Class I PSD Areas. The UTM coordinates of this facility are Zone 16; 488,970 km E; 3,381.350 km N.

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

The SREC is a new major facility. The new cogeneration facility identification number in the Department database (ARMS system) is F.I.D. No. 1130168. This facility will be located within the Sterling Fibers' chemical plant boundary but it is not part of the Sterling Fibers chemical plant operation or corporate ownership. However, SREL will provide steam and electricity to Sterling Fibers and electricity to the electric utility grid.

The new facility will be classified as a Major or Title V Source of air pollution because emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) exceed 100 TPY. The new facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions will be greater than 100 TPY for CO and NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) is required for these two pollutants.

Given that the project constitutes a Major Facility for CO or NO_X, emissions greater than 40 TPY of sulfur dioxide (SO_2) or volatile organic compounds (VOC), 25/15 TPY of particulate matter (PM/PM_{10}), etc., also require review per the PSD rules and a BACT determination.

This facility is subject to the Acid Rain Program, 40 CFR 72, because it is a combined cycle cogeneration facility constructed after 15 November 1990 and more than one-third of its potential electrical output capacity (greater than 219,000 MW-hrs of electricity) will be sold to a utility.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One 167 Megawatt (nominal) Gas Combustion Turbine-Electrical generator
002	Steam Generation	One 585 mmBtu/hr Supplementary-Fired Heat Recovery Steam Generator (HRSG) (and 74 Megawatt Steam Electrical Turbine)
003	Water Cooling	Cooling Tower

Santa Rosa Energy Center LLC (SREL) proposes to construct a nominal 241 megawatt (MW) natural gas-fired cogeneration facility. This cogeneration facility will consist of: a nominal 167 MW gas combustion turbine-electrical generator; a 585 million Btu per hour (mmBtu/hr) supplementary-fired heat recovery steam generator (HRSG); a 74 MW (gross output) steam turbine; a 200-foot stack; and ancillary equipment. This facility will be located within the boundaries of the existing Sterling Fiber chemical plant at 5005 Sterling Way in Pace, Santa Rosa County.

The turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors for the control of NO_X emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. The turbine will have a nominal heat input of 1,600 mmBtu/hr lower heat value (LHV) at ambient conditions and 60% relative humidity while operating at 100% load.

The (HRSG) will have a design fuel input capacity of 585 mmBtu/hr higher heat value (HHV) from the duct burner and approximately 971 mmBtu/hr from the combustion turbine exhaust. The duct burner will be of a "Low NO_X" design in order to control emissions of nitrogen oxides.

Without supplemental firing and at full load, enough steam can be raised to generate 74 MW from the steam turbine and provide some process steam to Sterling Fibers. Supplemental firing will increase steam production for electrical and process use by at least 60 percent at baseload. The firing capability allows for flexibility in meeting the steam demand from Sterling Fibers, within the capabilities and constraints of the burner system, the combustion turbine, and electrical demands.

When the cogeneration facility operates, the Sterling Fiber boilers will normally be off-line. This will result in a temporary significant reduction in NO_X emissions.

Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). Emission increases of SO_2, and H_2SO_4 will be less than their respective significant emission levels per Table 62-212.400-2, F.A.C. and do not require PSD or non-attainment new source review. PSD review is required for CO, PM/PM_{10}, NO_X, and VOC since emissions, per the application, will increase by more than their respective significant emissions levels.

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

An exterior view of the GE MS 7001FA (a predecessor of the MS 7241FA) is shown in Figure 1. The key components are identified in Figure 2. The unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of those shown in Figure 2.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

Figure 3 is a simplified process flow diagram showing the key plant components. In the SREL project, the unit will always operate in the combined cycle mode, meaning that the hot combustion turbine gases are further utilized rather than exhausted through a bypass stack. In this mode, the gas turbine directly drives an electric generator while the exhausted gases (containing a high excess air fraction) are used to raise steam in a HRSG. Because the HRSG will be equipped with a duct burner, the hot combustion turbine exhaust gases can be used as combustion air to raise additional steam by supporting the combustion of additional gas. Figure 4 is a diagram of an in-line duct burner manufactured by Coen.

In simple cycle mode, the thermal efficiency of the GE 7FA line of combustion turbines is about 35 percent. In combined cycle mode, with all steam used to generate electrical power, efficiencies of 56 percent are possible. Production of steam in the HRSG for electrical and process use (cogeneration), can result in efficiencies between 56 and 85 percent. The maximum value represents production of steam solely for process use. It is noted that the thermal efficiency of steam raised by the duct burners and used for process requirements is nearly 100 percent.

The project includes highly automated controls, described as the GE Mark V Control System. The SPEEDTRONIC Mark V Gas Turbine Control System is designed to fulfill all of the gas turbine control requirements.

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

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

This facility is located in Escambia County, an area designated as unclassifiable for SO_2 and attainment for all other criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, VOC and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, VOC, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

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

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration (PSD)
40 CFR 60	NSPS Subparts GG and Da
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Units will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, and negligible quantities of sulfuric acid mist, fluorides, beryllium, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 20 through 26 of Draft Permit PSD-FL-253.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutants	Combustion Turbine [1]	Duct Burner	Total	PSD Significance	PSD REVIEW?
PM/PM_{10}	41.6	13.1	55	25	Yes
SO_2	4.8	1.6	7	40	No
NO_X	271	131	402	40	Yes
CO	129	131	260	100	Yes
Ozone(VOC)	13	31	44	40	Yes
Sulfuric Acid Mist	<1	<1	<2	7	No
Total Reduced Sulfur	<1	<1	<2	10	No
Mercury	<<0.1	0.0004	<<0.1	0.1	No
Beryllium	<<0.0004	0.00002	<0.0004	0.0004	No
Lead	<<0.6	0.0008	<<0.6	0.6	No
Total HAPs	<10	3.1	<15	NA	No

1. Gas turbine emissions at 68 °F and 8,760 hours of operation. Duct Burner emissions at 64 percent availability. Mercury. beryllium, lead emissions are for duct burner only. With gas turbine they would still be insignificant for PSD review.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean natural gas. The gas turbine combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The DLN-2.6 combustors will control combustion turbine emissions of CO and NO_X to 9 ppm @15% O_2 between 50 and 100% of full load under normal operating conditions. Low NO_X burners will be utilized in the HRSG to achieve NO_X values of 0.05 lb/mmBtu heat input. Alternatives including selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are available if these rates cannot be achieved by Low NO_X technologies. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, NO_X, and VOC. PM_{10} and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO and VOC are criteria pollutants and have only AAQS and significant impact levels defined for them. Since the project's VOC emissions increase is less than 100 tons per year no air quality analysis is required for VOC.

The applicant's initial PM_{10}, CO and NO_X air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. The nearest PSD Class I areas are the Breton National Wilderness Area located 175 km to the southwest in Louisiana and the Bradwell Bay National Wilderness area located 200 km to the east. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10}, CO and NO_X;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved SCREEN3 (screening model) and Industrial Source Complex Short-Term (ISCST3) dispersion models were used to evaluate the pollutant emissions from the proposed project. These models determine ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. They incorporate elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Pensacola Airport, Florida (surface data) and Apalachicola, Florida (upper air data). The 5-year period of meteorological data was from 1985 through 1989. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility and in the PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the SCREEN3 model was used to evaluate dispersion of emissions from the cogeneration unit for four loads (50%, 65%, 75% and 100%) and three seasonal operating conditions (summer, winter, and average). If this modeling at worst-case load conditions shows significant impacts, additional multi-source modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments. Receptors were placed within 10 km of the facility, which is located in a PSD Class II area. They were also placed in the Breton National Wilderness Area (BNWA), which is the closest PSD Class I area. Breton is located approximately 175 km to the southwest of the project. The receptor grid for predicting maximum concentrations in the vicinity of the project was a rectangular receptor grid with 20 km by 20 km dimensions centered on the cogeneration facility stack. The inner portion of the grid had grid cells at 100 m spacing out to 1,000m. A 200 m spacing was used out to 3,000 m; and a 500 m spacing was used out to 5,000m. From 5,000 m to 10,000 m, a 1,000 m spacing was used. For predicting impacts at the BNWA, six discrete receptors along the border of the PSD Class I area were used. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the BNWA. The tables below show the results of this modeling.

Maximum Project Air Quality Impacts for Comparison to the PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Max Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	Significant Impact?
PM_{10}	Annual	0.02	1	NO
	24-hour	0.55	5	NO
CO	8-hour	6	500	NO
	1-hour	31	2000	NO
NO_2	Annual	0.1	1	NO

Maximum Project Air Quality Impacts for Comparison to the PSD Class I Significant Impact Levels (BNWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m3)	Proposed EPA Significant Impact Level (ug/m3)	Significant Impact?
PM_{10}	Annual	0.001	0.2	NO
	24-hour	0.01	0.3	NO
NO_2	Annual	0.004	0.1	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentration increases predicted to occur for PM_{10}, CO, NO_X, and VOC as a result of the proposed project are less than significant. As such, this project is not expected to have a harmful impact on soils, vegetation, wildlife, and visibility in both the PSD Class I and II areas. Even the minimal impacts will be ameliorated by decreased use of the less efficient and more polluting boilers normally providing process steam to Stirling Fibers.

Growth-Related Air Quality Impacts

The proposed project is a private sector investment. It will help meet current and future state-wide electric demands and the process steam requirements of Stirling Fibers, the steam host for the cogeneration project. Additional growth in the immediate area as a direct result of the additional electric power provided by the project is not expected The project itself will be constructed and operated with minimum labor and associated facilities and is not expected to permanently affect growth in the local area. Obviously any increase in highly efficient electric power capacity promotes or accommodates further state-wide growth.

Air Toxics

Both releases and ground level concentrations of hazardous air pollutants (HAPS) are below any applicable NSPS, NESHAP, and PSD threshold. The available air pollution control equipment for this project will have little impact on regulated HAPS.

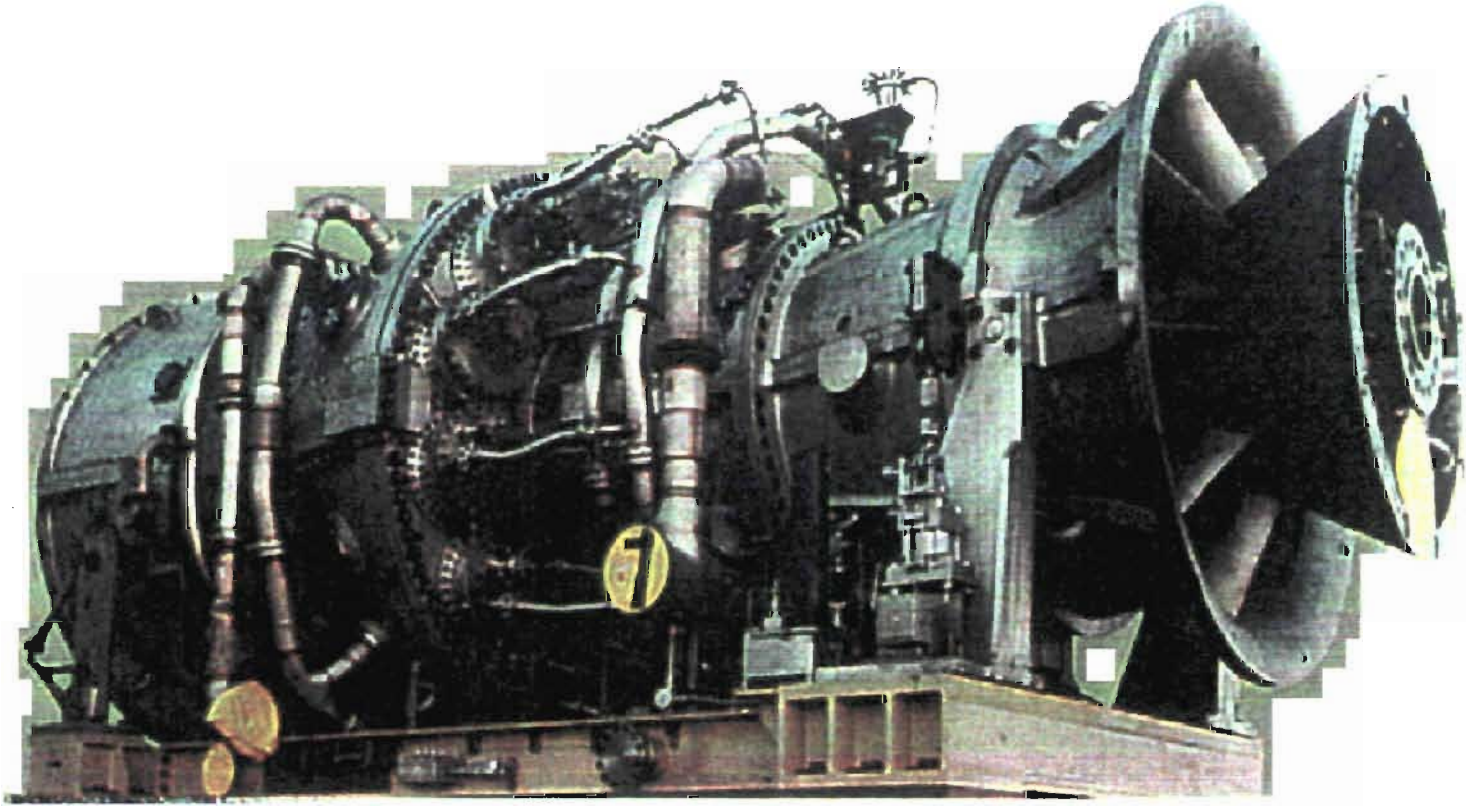
7. CONCLUSION

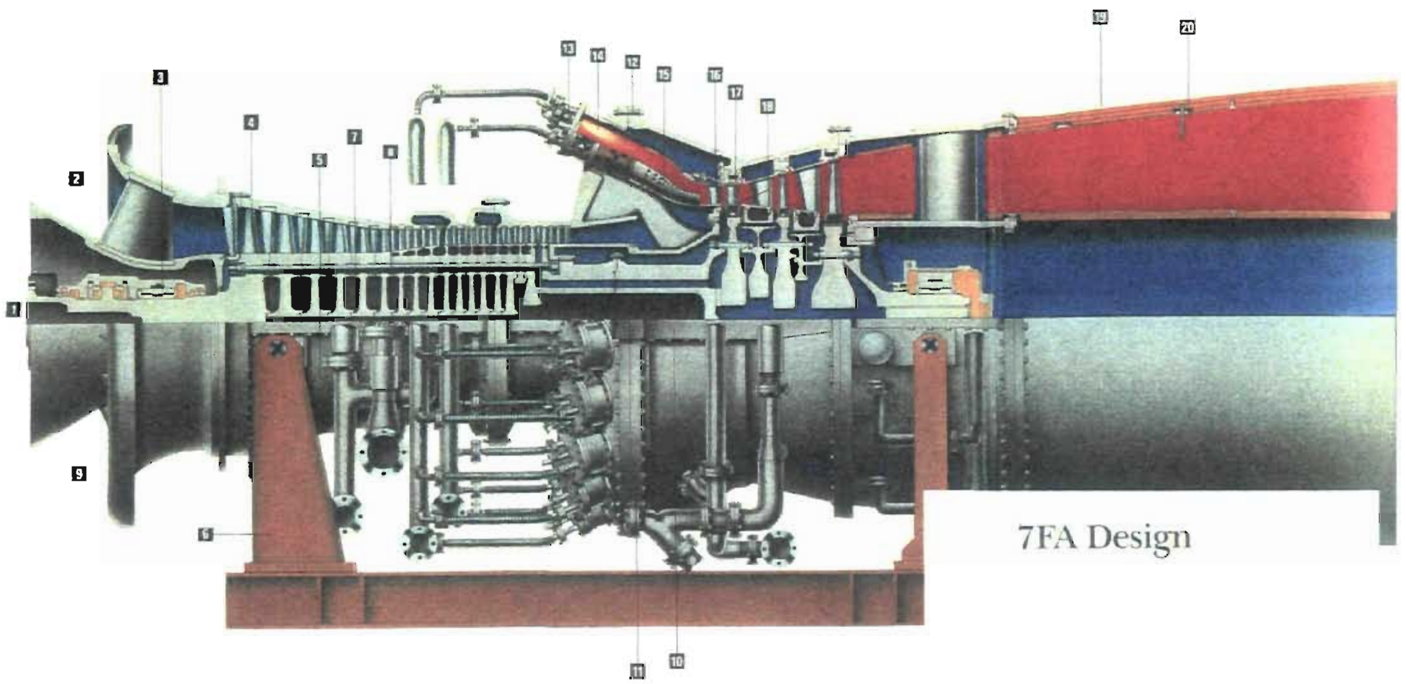
Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT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

Teresa Heron, Review Engineer
Cleve Holladay, Meteorologist

Reviewed and Approved by A. A. Linero, P.E.

Figure 1 - GE MS7001FA





COMPRESSOR

1. Load Coupling – short, rigid coupling can be directly connected to generator flange.

2. Axial/Radial Inlet Casing – proven design provides uniform inlet flow to compressor.

3. Journal Bearings – bearings are tilting-pad type for improved rotor stability and are also pressure-lift for reduced break-away torque.

4. Compressor Blading – an evolution from the 7EA compressor with a zero stage added. Blade length increased for added flow. Blade material upgraded for more demanding requirements. Shrouded stator 17 and exit guide vanes are utilized for improved cyclical life.

5. Compressor Design – based on proven axial-flow design. One piece casing allows easier start-up. Casing material upgraded to accommodate higher temperature and pressure.

6. Rigid Forward Support – in combination with forward thrust bearing, limits thermal expansion of gas turbine into generator.

7. Wheel Construction – machined to nearly constant stress cross-section with contact faces at maximum diameter for high rotor stiffness.

8. Through-Bolt Construction – large bolts at maximum bolt circle provide rigid rotor with required torque capability for front-end drive.

9. Inlet Orientation – available in up, down or side arrangement.

STATOR CASINGS

10. Horizontally Split – all casings split on horizontal centerline with through-bolting to facilitate maintenance.

COMBUSTION

11. Combustor Bulkhead – combustor outer cans attached over elongated holes in combustor bulkhead to permit removal of transition piece without lifting turbine shell.

12. Top and Bottom Manway Access – permits an alternative method for removing combustor transition piece and stage 1 nozzle without lifting turbine shell.

13. Fuel Distribution – single fuel line connection for each combustor with manifolding to six fuel nozzles built into combustor end cover.

14. Reverse Flow Combustor Chambers – supplement the impingement and film cooling of the liners, prolonging parts life.

15. Impingement Cooled Combustor Transition Piece – separate perforated sleeve around transition piece causes compressor discharge air to impinge on and effectively cool the transition piece.

TURBINE

16. Nozzle Design – sidewalls and internal surfaces of vanes impingement cooled with spent air used for extensive film cooling.

17. Stage 1 Stationary Shroud Design – gas path insert of high temperature alloy, extensively convection, impingement and film cooled and coated for maintaining tight clearances with the stage 1 bucket tip.

1st Stage *2nd Stage* *3rd Stage*

18. Bucket Design – stage 1 bucket is directionally solidified and uses a turbulated serpentine cooled design with trailing edge bleed cooling, based on GE Aircraft Engine technology. Stage 2 uses turbulated radial cooling holes. Stage 3 is uncooled. Stages 2 and 3 have integral z-lock shrouds for vibration control, and all three stages have long shanks for vibration control and isolation of gas path temperatures from the turbine wheels.

EXHAUST

19. Exhaust Diffuser – axial design (permitted by front-end drive) is blanket insulated for thermal stability, safety and reduced heat loss from exhaust before entering heat recovery system.

20. Exhaust Thermocouples – sets of thermocouples supply signals to each of the three SPEEDTRONIC™ Mark V computers. The thermocouples are used for control and also for monitoring the combustion system.

Figure 2 - GE Combustion Turbine MS 7001FA

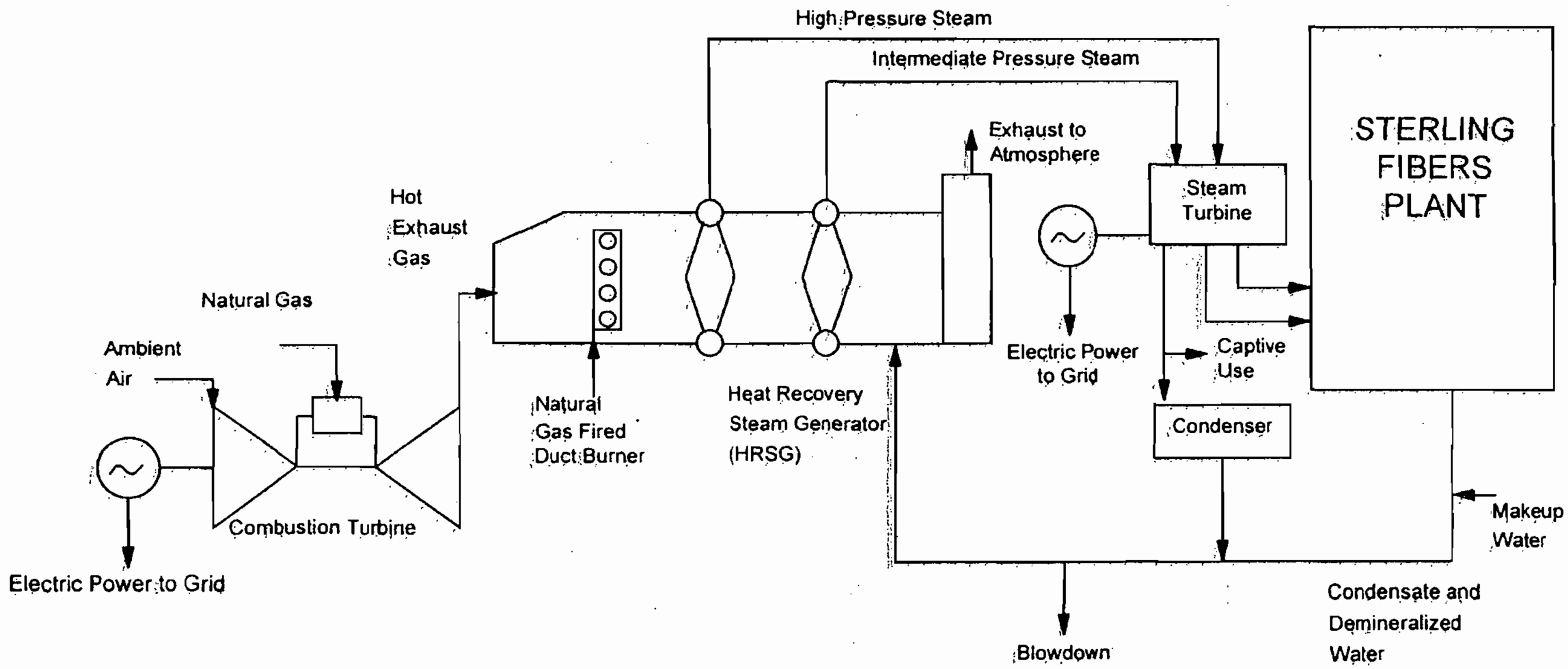


Figure 3 - Combined Cycle Cogeneration Process

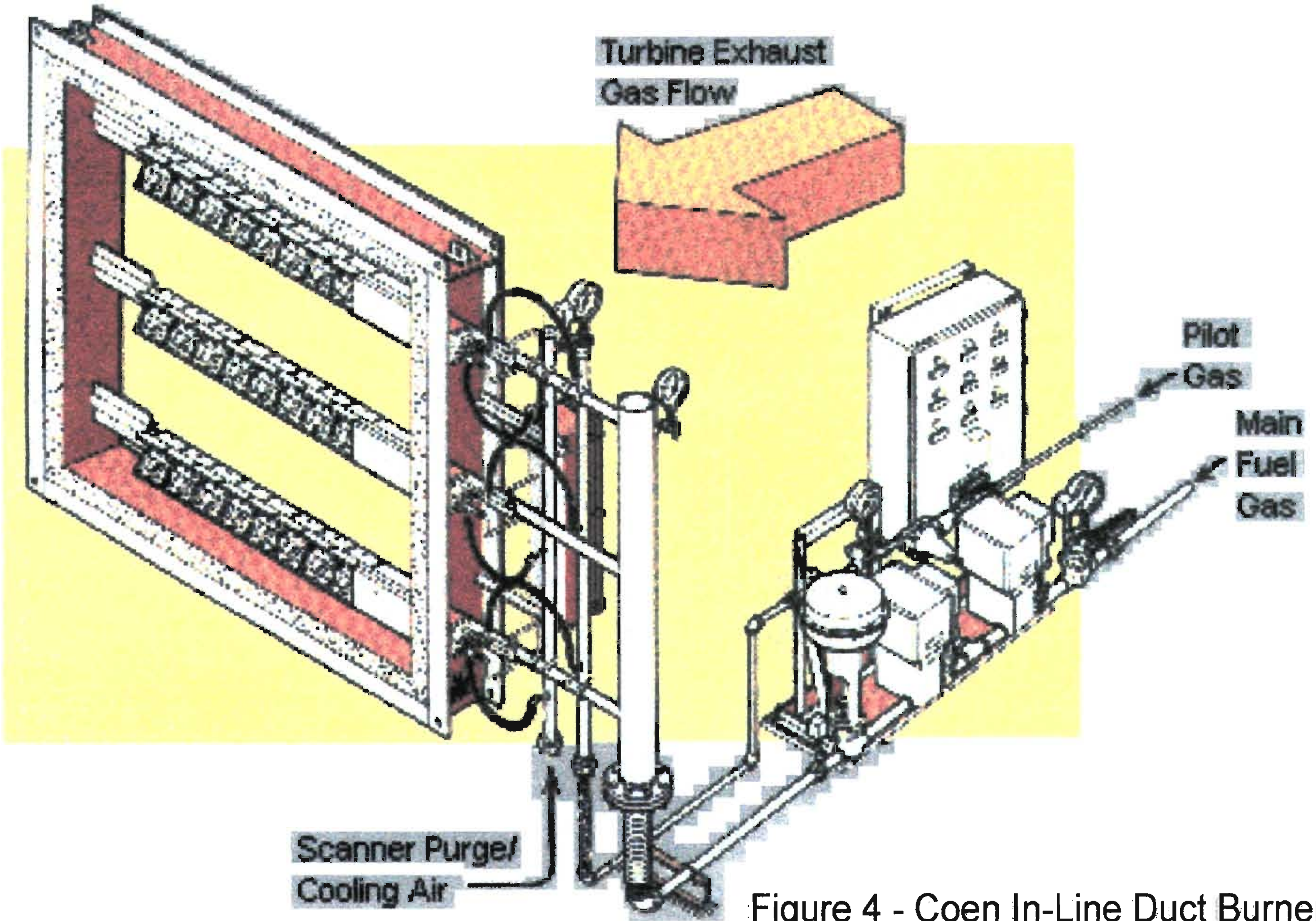


Figure 4 - Coen In-Line Duct Burner

PERMITTEE:

Santa Rosa Energy LLC
650 Dundee Road
Northbrook, Illinois 60062

Authorized Representative:

James Shield, Vice-President

DEP File No.	1130168-001-AC
Permit No.	PSD-FL-253
Project	241 MW Cogeneration Plant
SIC No.	4911
Expires:	December 31, 2001

PROJECT AND LOCATION:

Permit for the construction of a natural gas-fired cogeneration plant that will consist of a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent steam host; a 200 foot main stack; and ancillary equipment. The facility is designated as the Santa Rosa Energy Center and will be located within the boundary of the Sterling Fiber Chemical Plant in Pace, Santa Rosa, County.

UTM coordinates are: Zone 16; 488.970 km E and 3,381.350 km N.

STATEMENT OF BASIS:

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

ATTACHED APPENDICES MADE A PART OF THIS PERMIT:

Appendix BD — BACT Determination
Appendix GC — Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

DRAFT 10/9/98

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This new major facility is a natural gas-fired 241 megawatt (MW) cogeneration plant that will consist of a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent steam host; a 200 foot main stack; and ancillary equipment. Supplemental firing will be by a duct burner rated at 585 million Btu per hour heat input.

Emissions from the combustion turbine will be controlled by Dry Low NO_X combustors, use of pipeline natural gas and good combustion while emissions from the duct burner arrangement will be controlled by Low NO_X burners, use of pipeline natural gas, and good combustion.

This Project, as presented, is exempt from the applicable requirements of Chapter 403, Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is less than 75 MW. [F.S. Chapter 403.503 (12). Definitions]

The new facility will be located on the site of the steam host, Sterling Fiber, which is a manufacturer of acrylonitrile-based fibers.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 167 Megawatt (nominal) Gas Combustion Turbine-Electrical Generator
002	Steam Generation	One 585 mmBtu/hr Duct Burner in a Supplementary Fired Heat Recovery Steam Generator (and 74 MW Steam Electrical Turbine)
003	Water Cooling	Cooling Tower

SUBSECTION C. REGULATORY CLASSIFICATION

The new facility will be classified as a Major or Title V Source of air pollution because emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) exceed 100 TPY. The new facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions will be greater than 100 TPY for CO and NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) is required for these two pollutants.

SECTION I. FACILITY INFORMATION

Given that the project constitutes a Major Facility for CO or NO_X, emissions greater than 40 TPY of sulfur dioxide (SO_2) or volatile organic compounds (VOC), 25/15 TPY of particulate matter (PM/PM_{10}), etc., also require review per the PSD rules and a BACT determination.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

PERMIT SCHEDULE

- 10/XX/98 Notice of Intent published in ______________.
- 10/09/98 Distributed Intent to Issue Permit.
- 09/08/98 Application deemed complete.
- 07/08/98 Received Application.

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received July 8, 1998.
- Department letter dated August 3, 1998.
- EPA comments received August 11, 1998.
- Comments and additional information received from the applicant on September 8, 1998.
- Department's Intent to Issue and Draft permit (including Draft BACT Determination) issued October 9, 1998.
- Comments from the National Park Service received on 10/XX/98.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

DRAFT 10/09/98

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northwest District office (DEPNW), 160 Governmental Center, Pensacola, Florida 32501-5794 and phone number 850/595-8300.

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

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

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Permit Approval: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. Permit Extension: *This permit expires on December 31, 2001.* The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

8. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]

SECTION II. ADMINISTRATIVE REQUIREMENTS

9. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northwest District office (DEPNW). [Chapter 62-213, F.A.C.]

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

11. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northwest District office by March 1st of each year.

12. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's Northwest District office.

DRAFT 10/09/98

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Unit 001, Power Generation, consisting of a 167 megawatt combustion turbine shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 002, Steam Generation, consisting of a supplementary-fired heat recovery steam generator equipped with a 585 mmBTU/hr Duct Burner shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The modification of 40CFR60, Subpart Da promulgated on September 3, 1998 also applies to this project.

6. ARMS Emission Unit 003, Cooling Tower, is an unregulated emission unit.

7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Northwest District office.

GENERAL OPERATION REQUIREMENTS

8. <u>Fuels</u>: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

9. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of the fuel at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,600 Btu per hour (mmBtu/hr). These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate, shall not exceed 585 mmBtu/hour. Annual natural gas usage in the Duct Burner shall not exceed 3,280 x 10^6 scf. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

12. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Northwest District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

13. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

14. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

15. Maximum allowable hours of operation for the 241 MW Cogeneration Plant are 8760. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine and Low NO_X burners shall be installed in the duct burner arrangement to comply with the NO_X emissions limits listed in Specific Condition 20 and 21. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. The permittee may design the heat recovery steam generator to accommodate installation of selective catalytic reduction or selective non-catalytic reduction or oxidation catalyst technologies and comply with the corresponding NO_X and CO limits listed in Specific Conditions 20, 21 and 22. [Rules 62-212.400 and 62-4.070, F.A.C.]

18. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 26. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)].

19. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. 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. 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. Each Unit shall be tested alone to comply with the applicable NSPS and as a Combined Unit to comply with the BACT limits as indicated below: [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG and Da), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	VE (%)	SO_2 (gr S/100 scf)	Comments
Combustion Turbine On Duct Burner Off	9 (24-Hr) - DLN 6 (3-Hr) - SCR	9	1.4	10	<20 - (fuel)	Natural Gas Good Combustion
Combustion Turbine On Duct Burner On	9.8 (24-Hr) - DLN/Low NO_X 6 (3-Hr) - DLN/SCR 6 (3-Hr) - DLN/SNCR	24	8	10	<20 - (fuel)	Natural Gas Good Combustion

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

21. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on shall not exceed 9.8 ppmvd at 15% O_2 (24-hr block average), and with the combustion turbine operating and the duct burner off shall not exceed 9 ppmvd at 15% O_2 (24-hour block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 106 pounds per hour (lb/hr) with the duct burner on and 64.1 lb/hr with the duct burner off to be demonstrated by initial stack test. [40CFR60 Subpart GG, Subpart Da and Rule 62-212.400, F.A.C.]
- If selective catalytic or non-catalytic reduction technology is installed, the concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on or off, shall not exceed 6 ppmvd @15% O_2 on a 3-hr block average. Compliance will be determined by the continuous emission monitor (CEMS). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 71 pounds per hour (lb/hr) with the duct burner on and 42.4 lb/hr with the duct burner off to be demonstrated by initial stack test. [40CFR60 Subpart GG, Subpart Da and Rule 62-212.400, F.A.C.]
- Emissions of NO_X from the duct burner shall not exceed 0.4 lb/MW-hr (gross output). [Rule 62-212.400, F.A.C. and 40CFR60 Subpart Da]
- 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.

22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither 24 ppm nor 75 lb/hr with the duct burner on and 9 ppm nor 29 lb/hr with the duct burner off to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall exceed neither 8 ppm nor 14 lb/hr with the duct burner on and 1.4 ppm nor 2.9 lb/hr with the duct burner off to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

24. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing only pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot). Compliance this requirement with in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 45 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. [40CFR60 Subparts Da and GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

25. Particulate Matter emissions : PM/PM_{10} emissions from the *duct burner* shall not exceed 0.03 lb/mmBTU measured by Method 5 or Method 17. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. [40CFR60 Subpart Da and 62-4.070 F.A.C.]

26. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner and shall not exceed 10 percent opacity from the stack. [40CFR60 Subpart Da, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

27. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from cogeneration plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

28. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

29. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Northwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 and 21. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1997 version)].

COMPLIANCE DETERMINATION

30. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

31. Initial (I) performance tests shall be performed by the deadlines in condition 30. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of SCR or SNCR (if required). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5 or Method 17, Determination of Particulate Emissions From Stationary Sources (I, at stack only).
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG, Da. NO_X BACT limits compliance by CEMs (24-hr average or 3-hr average if SCR/SNCR is required).
    - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

32. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 29. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

33. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when

determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

34. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75.

35. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

36. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

37. Test Notification: The DEP's Northwest District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

38. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

39. Test Results: Compliance test results shall be submitted to the DEP's Northwest District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

40. Records: All measurements, records, and other data required to be maintained by Santa Rosa Energy Center shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

41. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

42. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Periods when NO_X emissions (lb/hr) are above the BACT standards, listed in Specific Condition No 20 and 21, shall be reported to the DEP Northwest District Office pursuant to Rule 62-4.160(8), F.A.C. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

43. CEMS for reporting excess emissions: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

44. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location (the monitoring plan) shall be provided to the Department's Emission Monitoring Section in Tallahassee for review at least 90 days prior to installation.

45. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

   - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
   - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
   - Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

47. Subpart Da Monitoring: The permittee shall comply with the applicable monitoring requirements of 40 CFR60, Subpart Da.

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APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Santa Rosa Energy Center
Permit No. 1130168-001-AC (PSD-FL-253)
Pace, Santa Rosa County, Florida

BACKGROUND

The applicant, Santa Rosa Energy LLC (SREL), proposes to install a combined-cycle cogeneration plant at the Sterling Fibers Facility located at 5005 Sterling Way, Pace, Santa Rosa County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 167 MW, General Electric 7FA combustion turbine-electrical generator, fired exclusively with pipeline natural gas. The project includes a supplementary-fired heat recovery steam generator (HRSG) and a steam turbine-electrical generator to produce an additional 74 MW of electrical power. A portion of the steam produced will be at the host Sterling Fibers Plant. The unit will exhaust through a 200 foot stack. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated October 7, 1998, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on July 8, 1998 and included a proposed BACT proposal prepared by the applicant's consultant, Roy F. Weston. Additional information amending the application and BACT proposal was received on September 8.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E., and Teresa Heron, Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas Combustion Controls	0.0051 lb/MMBtu (CT) 0.0080 lb/MMBtu (DB)
Volatile Organic Compounds	As Above	1.4 ppm (CT) 0.0190 lb/MMBtu (DB)
Carbon Monoxide	As Above	9 ppm (CT) 0.080 lb/MMBtu (DB)
Nitrogen Oxides	Dry Low NO_X Combustors Dry Low NO_X Burners	9 ppm @ 15% O_2 (CT) 0.08 lb/mmBtu (DB)

According to the revised application, the units, would emit approximately 402 tons per year (TPY) of NO_X, 260 TPY of CO, 45 TPY of VOC, 7 TPY of SO_2, and 55 TPY of PM/PM_{10}.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by SERL is consistent with Subpart GG NSPS which allows NO_X emissions of approximately 110 ppm for the high efficiency unit to be purchased by the Santa Rosa Energy LLC.

The fired duct burner required for supplementary gas-firing of the HRSG is subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The BACT proposed by SERL is consistent with the key historically applicable NSPS requirement of 0.20 pounds of NO_X per million Btu heat <u>input</u> (lb NO_X/mmBtu). It is well below the revised Subpart Da <u>output</u>-based limit of 1.6 lb NO_X/MW-hr promulgated on September 3, 1998.

No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on recent limitations set by EPA and the States for comparable stationary gas turbine.

Project Location	Power Output and Duty	NO_X Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Lakeland, **FL**	350 MW CC CON	9/9/7.5 - NG 42/15/15 - No. 2 FO	DLN/HSCR/SCR WI/HSCR/SCR	230 MW WH 501G CT Initially 250 MW simple cycle and 25 ppm NO_X limit on gas
Mid-GA Cogen	308 MW CC CON	9 - NG 20 - No. 2 FO	DLN & SCR	2x119 MW WH 501D5A CTs
Fort Myers, **FL**	1500 MW CC CON	9 - NG	DLN	6x170 MW **GE MS 7241** CTs Draft Permit, Non-BACT
Tiger Bay, **FL**	270 MW CC CON	15/10 - NG 42 - No. 2 FO	DLN &/or SCR WI	184 MW GE MS7001**FA** CT DLN/15 ppm or SCR/10 ppm
Hines Polk, **FL**	485 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW WH 501**FC** CTs Canceled GE CTs
Tallahassee, **FL**	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231**FA** CT DLN guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC CON	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW WH 501**F** CTs
Sithe/IPP, NY	1012 MW CC CON	4.5 - NG	DLN & SCR	4x160 MW GE 7**FA** CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW GE 7**FA** CTs
Barry, AL	800 MW CC CON	3.5 - NG (CT/DB)	DLN & SCR	3x170 MW GE 7**FA** CTs

CC = Combined Cycle
DB = Duct Burner
NG = Natural Gas
CT = Combustion Turbine
CON = Continuous
HSCR = Hot SCR
FO = Fuel Oil
ISO = 59°F
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
LPG = Liquefied Propane Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari
ppm = parts per million
Factors in Common with Santa Rosa Energy LLC Project are bolded.

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Mid-GA Cogen,	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
Fort Myers, FL	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Tiger Bay, FL	0.045 lb/mmBtu-NG 0.053 lb/mmBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Barry, AL	0.034 lb/mmBtu - NG/CT 0.057 lb/mmBtu - CT/DB	0.015 lb/mmBtu After CT and DB	0.011 lb/mmBtu - CT/DB 10% Opacity	Gas Only Good Combustion

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

The following table is a sample of information on recent NO_X limitation by EPA and the States for combined cycle and cogeneration projects incorporating supplementary-firing in heat recovery steam generators.

Project Location	Duct Burner Rated Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu or ppm)	Technology	Comments
Plant Berry, AL	159	0.018 mmBtu/hr	DLN, SCR	3x170 MW GE 7FA CTs 3 Duct Burners
Saranac Energy, NY	553	0.08 lb/mmBtu	SCR	2 GE 7EA CTs with DBs Permit issued 1992
Bermuda HEL, VA	197	9 ppm	Steam Injection, SCR	1175 mmBtu/hr CT (1992)
Bear Island Paper, VA	129	9 ppm	SCR	474 mmBtu/hr CT (1992)
Pilgrim Energy, NY	214	4.5 ppm (CT) 0.012 lb/mmBtu (DB)	Steam Injection, SCR Low NO_X Burner, SCR	2 WH 501D5 CTs 2 Duct Burners
Selkirk Cogen, NY	206	9 ppm (CT) 0.018 lb/mmBtu (DB)	Low NO_X Burner, SCR	1173 mmBtu/hr CT
Grays Ferry, PA	366	9 ppm (CT) 0.09 lb/mmBtu (DB)	DLN Low NO_X Burner	WH 501D5A CT with DB DLN Failed, SCR Required

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Letter from EPA Region IV dated August 11, 1998
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

COMBUSTION TURBINE AND DUCT BURNER CONTROL TECHNOLOGIES:

The applicant presented an analyses of the different available control technologies for all of the pollutants subject to PSD review and a BACT determination. The applicability of these measures is best understood in conduction with the mechanisms by the pollutants are generated.

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Nitrogen Oxides Formation

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

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

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in lean, near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the SREL project because only natural gas will be used.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

The potential for NO_X emissions from gas-fired duct burners is lower than from gas turbines because of the lower temperature and pressure. In a supplementary-fired duct burner, the gas to the HRSG is raised from approximately 1100 to less than 1800 °F. Thermal NO_X formation essentially ceases at temperatures below 2000 °F.[1] Since the fuel contains virtually no nitrogen, there is little potential for fuel NO_X formation either.

NO_X Control Techniques

Combustion Controls

The excess air in lean combustion, cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel

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in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

The emission characteristics of General Electric's DLN 2 combustors are given in Figure 2. NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity. GE has since further upgraded its combustors and this description is not precise for its more advanced DLN-2.6.

Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the SREL project are shown in Figure 3. The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle to achieve 9 ppm of NO_X and 9 ppm of CO at somewhat less than 50 percent load. Presumably the emission characteristics of the DLN-2.6 are similar are similar to the DLN 2, except that the combustor emits NO_X at concentrations of 9 ppm (instead of the 25 ppm shown in Figure 2) at loads between 50 and 100 percent. Because of the "totally pre-mixed" design, emissions at less than 50 percent load are probably also lower for the DLN 2.6 than the DLN-2.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, results in a lower achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to the steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle), such as the F class. As in the case of wet injection, higher CO and hydrocarbon emissions can occur as a result of employing combustion controls to minimize NO_X.

Figure 5 is a diagram of a typical in-line duct burner configuration and individual burner manufactured by Coen, one of the potential providers of this equipment. The unit will reside within the duct between the combustion turbine outlet and the HRSG. The oxygen-rich, hot turbine exhaust is used to burn natural gas introduced through the burner arrangement. In contrast to the pre-mixing that can be accomplished in the combustion turbine, not much (other than design optimization) can be done regarding the manner by which the very large volume of hot combustion air and the fuel are mixed prior to combustion. Basically the burners are described as Low NO_X burners.

There have been reports of lower emissions (on a lb/mmBtu or ppm basis rather than on a lb/hr basis) with the duct burners on. It has been theorized that the results are "suspect" and may have been cause by the "inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.".[2] It has also been theorized that transformations between NO and NO_2, interfere with the test method.[3] As previously mentioned, since the duct burner operates at a lower temperature and pressure than the gas turbine, it is possible that concentrations may actually be lower with the duct burner on.

<u>Selective Catalytic Combustion</u>

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas. As of early 1992, over 100 gas turbine installations already used SCR in the United States. No combustion turbines in Florida employ SCR. Virtually all SCR units are used in combination with wet injection or combustion controls.

Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

In a manner analogous to balancing control of NO_X from the combustor with emissions of CO and hydrocarbon, similar balancing is required when controlling NO_X by SCR. Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit BACT limits as low as 3.5 ppm NO_X have been specified using SCR for an F Class project (with small in-line duct burners) in Alabama and proposed for another F Class project in Mississippi.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F: A supplementary-fired unit (such as the SREL project) is defined as an HRSG fired to an average temperature not exceeding about 1800 °F. The 585 mmBtu/hr duct burner described by SREL will achieve temperatures close to this value. Although no SNCR applications are known, the technology appears to be feasible and possibly less complicated than SCR.

Carbon Monoxide (CO) Control

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 Berkshire, Massachusetts facility, 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppm at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the CT value of 9 ppm baseload proposed by SREL appears relatively low, but consistent with the capabilities of DLN-2.6 technology as discussed above. This proposed limits are achievable through good combustion practice. When simultaneously operating the combustion turbine and the duct burner, CO concentrations emissions will be less than 24 ppm which is within the range of limits set for combustion turbines operating alone. Annual emissions of CO are expected to be less than 260 tons per year (combustion turbine and duct burner).

Volatile Organic Compound (VOC) Control

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC for both the turbine and the duct burner. The CT proposed limit is 1.4 ppm . According to GE, even lower VOC emissions were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[4] VOC concentrations will be less than 8 ppm for simultaneous operation of the combustion turbine and duct burner.

Particulate Matter (PM/PM_{10}) Control

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas will be the only fuels fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. This has been chosen as BACT by the applicant, the Department concurs. Annual emissions of PM/PM_{10} are expected to be less than 55 tons per year (combustion turbine and duct burner).

Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required.

BACKGROUND ON SELECTED GAS TURBINE AND DUCT BURNER

SERL plans to the purchase a 167 MW (nominal) General Electric 7FA combined cycle gas turbine with a supplementary-fired heat recovery steam generator (HRSG) equipped with a duct burner and a steam turbine-electrical generator to produce an additional 74 MW (nominal) of electrical power and process steam.

The 585 mmBtu/hr duct burner will be manufactured by Coen or equivalent and will be a low NO_X design. For reference, the heat rate of a combustion turbine with a 600 mmBtu/hr supplementary-fired duct burner used to make only electrical power is 4,350 Btu/KW-hr.[5] In cogeneration mode, if only 50 percent of the process steam generated is considered, the heat rate is even lower. This compares with the presumed heat rate of 10,667 Btu/KW-hr in the recently revised NSPS Subpart Da.[6]

The first commercial GE 7F Class unit was installed at the Virginia Power Chesterfield Station in 1990.[7] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppm These actually achieve less 25 ppm of NO_X and 15 ppm of CO. The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppm of NO_X, the City obtained a performance guarantee from GE of 9 ppm.[10] FPL also obtained a guarantee of 9 ppm for six GE 7241FA turbines to be installed at the Fort Myers Repowering project. These limits were incorporated in the draft permit issued for the project.[11]

General Electric, other manufacturers, and their customers are relying on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[12]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7FA units met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.[13] Although the permitted limit is 15 ppm, GE has already achieved emission levels of approximately 6 ppm on gas at a dual-fuel 7EA (120 MW combined cycle) unit at Cane Island Power Park in Kissimmee, FL.[14] The Cane Island unit is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line and performance guarantees less than 9 ppm can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[15]

The 9 ppm NO_X limit on natural gas during baseload requested by SREL is typical compared with recent BACT determinations for F Class units, such as those previously listed.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V Control System, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V Control System.[16]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the SERL project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 and 21.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	1.4 ppm (CT on, DB off) 8 ppm (CT and DB on))
CO	As Above	9 ppm (CT on, DB off) 24 ppm (CT and DB on)
NO_X (CT on, DB off)	DLN or SCR	9 ppm or 6 ppm
NO_X (CT and DB on)	DLN and Low NO_X, or SNCR, or SCR	9.8 ppm, or 6 ppm, or 6 ppm DB limited to 0.4 lb/MW-hr

RATIONALE FOR DEPARTMENT'S DETERMINATION

- SERL can obtain a guarantee from GE for DLN-2.6 combustors which have been demonstrated to meet all of the above limits on 7FA Class gas turbine with the duct burner off.
- The turbine emission limits with the duct burner off comply with the NSPS and are less than or equal to recent Department BACT determinations applicable to new units at start-up.
- VOC emissions of 1.4 ppm from the combustion turbine proposed by SERL are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels

with the DLN-2.6 combustors while firing natural gas. The limit of 8 ppm with the duct burner on is also quite low.

- The duct burner used for supplementary firing will comply with the NSPS (Subpart Da). It will cause sligthly higher NO_X concentrations than permitted for the combustion turbine alone.
- If a different combustion turbine is selected or if the NO_X limits cannot be met with Low NO_X technology with the duct burner on, SERL must install either SNCR or SCR technology and meet correspondingly lower emission limits achievable by the latter technologies.
- The levelized costs of NO_X reduction to 3.5 - 6 ppm by conventional SCR installed in the HRSG were estimated by SERL as $4,660 - 5,247 per ton of NO_X removed after initial control by DLN to 9 ppm. The Department's estimates the levelized costs at $2,500 per ton of NO_X removed starting with DLN combustion control to 25 ppm. This figure does not reflect a possible credit for savings by purchasing the less expensive line of combustors such as the GE DLN-1 or DLN-2 in lieu of the DLN 2.6 combustors. Neither the Department nor the SERL estimates reflect the cost-effectiveness of duct burner-generated NO_X removal.
- If the combined unit can meet applicable limits by DLN with the duct burner off but not with the duct burner on, SNCR can be utilized when the duct burner is on. SNCR is less expensive and more cost-effective than SCR. It can be turned off when the duct burner is off since the proper operating temperature range will not exist under that mode.
- SCR and SNCR cause environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. At equal emission rates, DLN technology is a better control strategy than SCR or SNCR. At higher emission rates, DLN can still be justified as BACT given the negative effects of SCR described above. Accordingly, the Department has set a range of emission limits and control methods based on the turbine and duct burner combustion technologies chosen by SREL.
- The Department's overall BACT determination is equivalent to approximately 0.16 lb/MW-hr by DLN/Low NO_X or 0.10 lb/MW-hr by SCR or SNCR. For reference, NSPS promulgated on September 3, 1998 requires that new Da units meet a limit of 1.6 lb/MW-hr.
- The Department considers a limit of 9.8 ppm (DLN and Low NO_X) or 6 ppm (SCR or SNCR) as BACT for this cogeneration facility. In addition the contribution of the duct burner to overall emissions cannot exceed 0.4 lb/MW-hr.
- The CO concentrations of 9 ppm are very low with the duct burner off. With the duct burner on, they will be less than 24 ppm which is within the range of recent Department BACT determinations for combustion turbines alone. The Department will set CO limits achievable by good combustion equal to 9 ppm for the combustion turbine and 24 ppm when the duct burner is on. For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppm on gas while the limit for the FPL Fort Myers project is 12 ppm. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- SREL evaluated the use of an oxidation catalyst designed for 85 percent reduction and having a three year catalyst life. The oxidation catalyst control system was estimated by SREL to increase

the total capital cost of the project by $1,462,846, with an annualized cost of $548,257 per year. SREL estimated levelized costs for CO catalyst control at about $2,481 per ton to control CO emissions to 39 TPY (from 260 TPY).

- The VOC emission concentration of 1.4 ppm proposed by SREL is at the lower end of values determined as BACT for the combustion turbine alone. Good Combustion is sufficient to achieve these low levels. With the duct burenr on, the levels are still relatively low except at very high operating rates.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, and the FPL Fort Myers projects in Florida as well as the Barry, Alabama project.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 29 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: For 1 hour following a shutdown less than or equal to 8 hours.
Warm Start: For 2 hours following a shutdown between 8 and 48 hours.
Cold Start: For 4 hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the unit has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[17]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

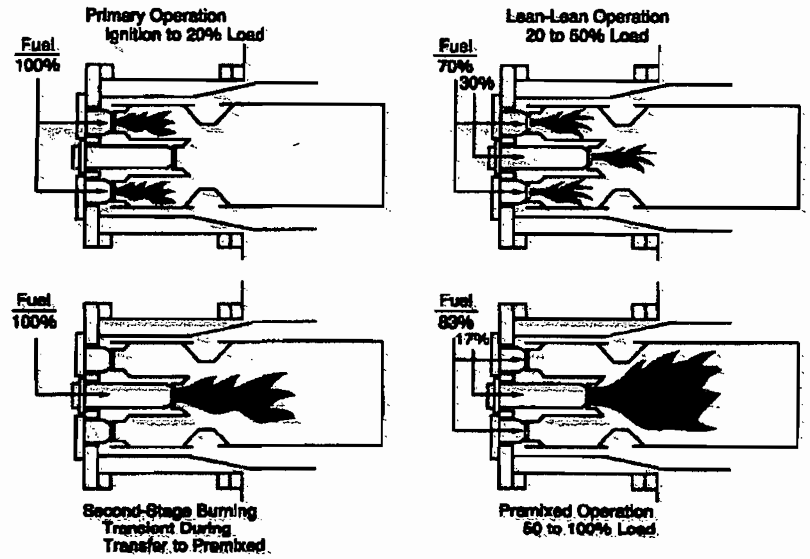
A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

DRAFT 10/05/98

References

[1] Report. EPA. "Summary Report - Control of NO_X Emissions by Reburning." Document EPA/625/R-96/001. February, 1996.
[2] Letter. Harper, J. A., EPA Region IV to Fancy, C., Florida DEP. June 3, 1994. Construction Permit Amendment for Orlando Cogen Limited, L.P.
[3] Verbal Communication. Harley, M., Florida DEP, and Linero, A. A., Florida DEP. September 18, 1998. Custom Fuel Monitoring and NSPS Da and Db Applicability.
[4] Telecon. Vandervort, C., GE, and Linero, A. A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."
[5] Fisk, R.W. and VanHousen, R. L., GE. "Cogeneration Application Considerations." 1996.
[6] Report. EPA. "New Source Performance Standards, Subparts Da and Db - Summary of Public Comments and Responses." Document EPA-453/R-98-005
[7] Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.
[8] Davis, L.B., GE. "Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines." 1994.
[9] Florida DEP. PSD Permit, City of Tallahassee Purdom Unit 8. May, 1998.
[10] City of Tallahassee. PSD/Site Certification Application. April, 1997.
[11] Florida DEP. Intent to Issue Permit. FPL Fort Myers Repowering Project. September, 1998.
[12] State of Alabama. PSD Permit, Alabama Power/Barry Sithe/IPP (GE 7FA).
[13] Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program
[14] Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.
[15] Telecon. Schorr, M., GE, and Linero, A. A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.
[16] Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."
[17] General Electric. Combined Cycle Startup Curves. June 19, 1998.



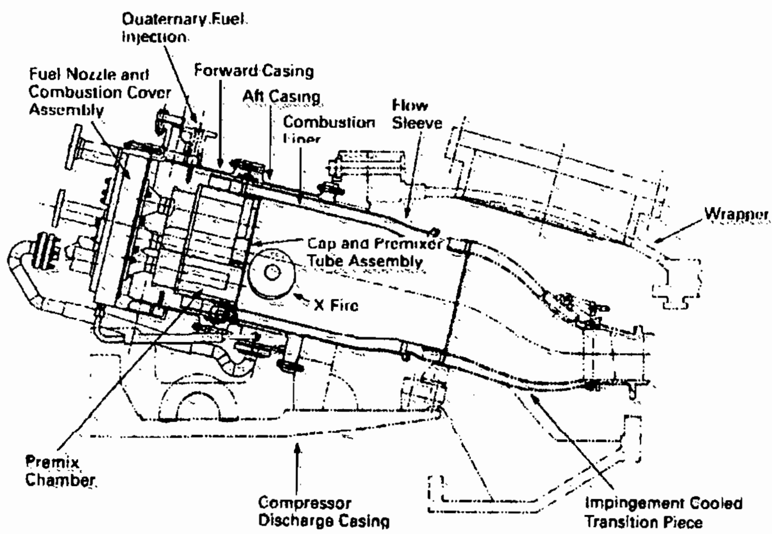


Figure 1 - Dry Low NOX Operating Modes - DLN-1

Cross Section of DLN-2.0

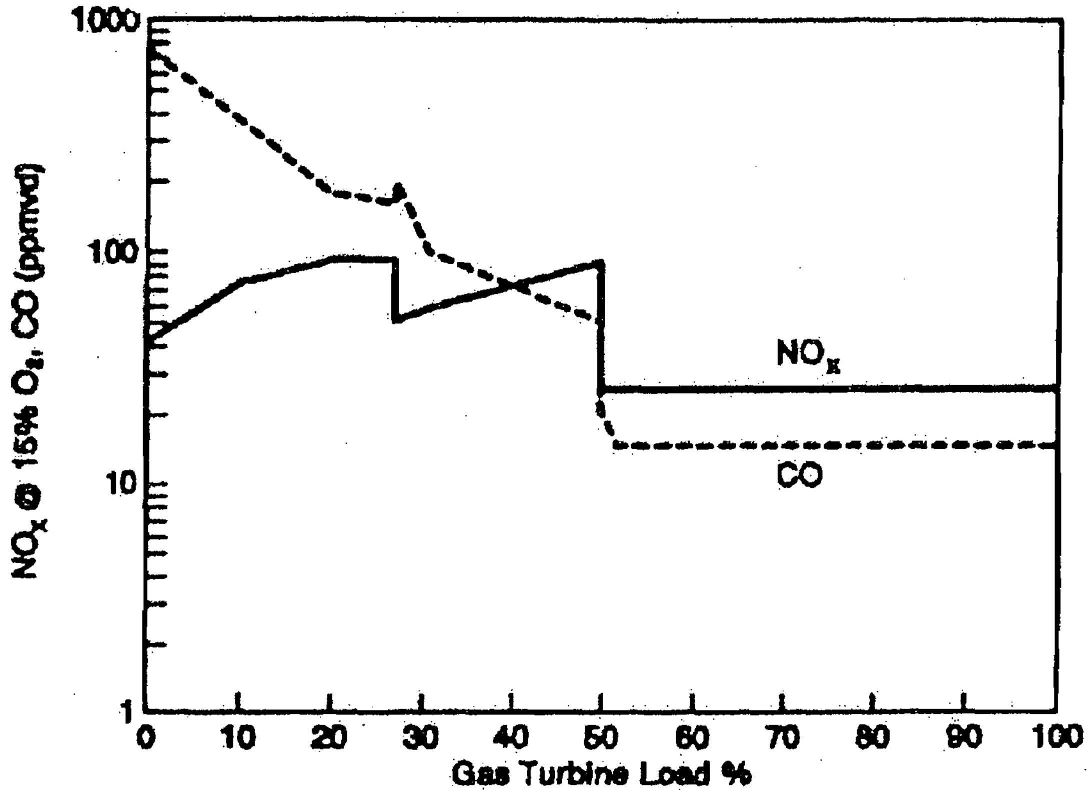


Figure 2 - Emissions Performance Curves for GE DLN-2 Combustors

Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

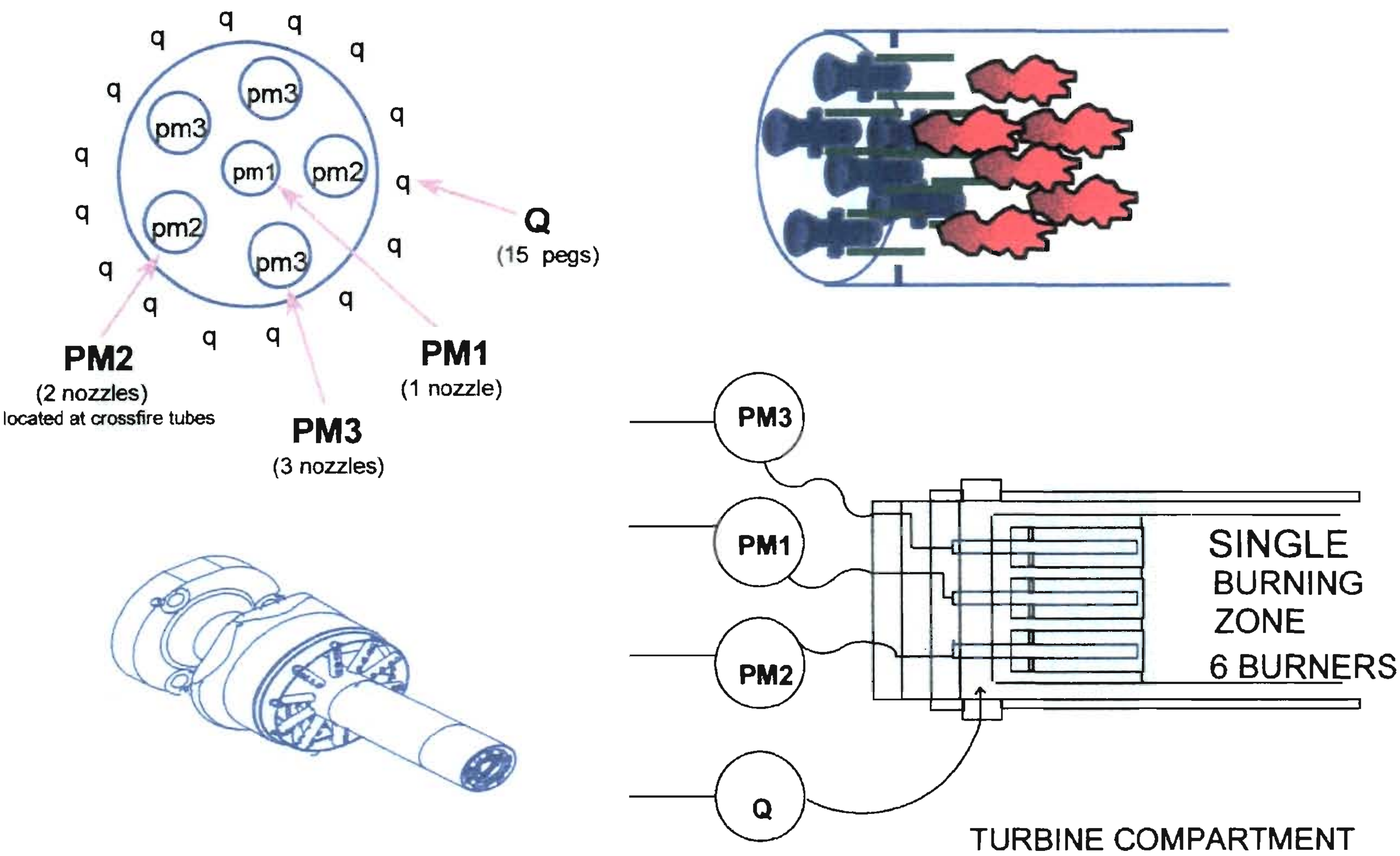


Figure 3 - GE DLN-2.6 Combustor and Nozzle Arrangement

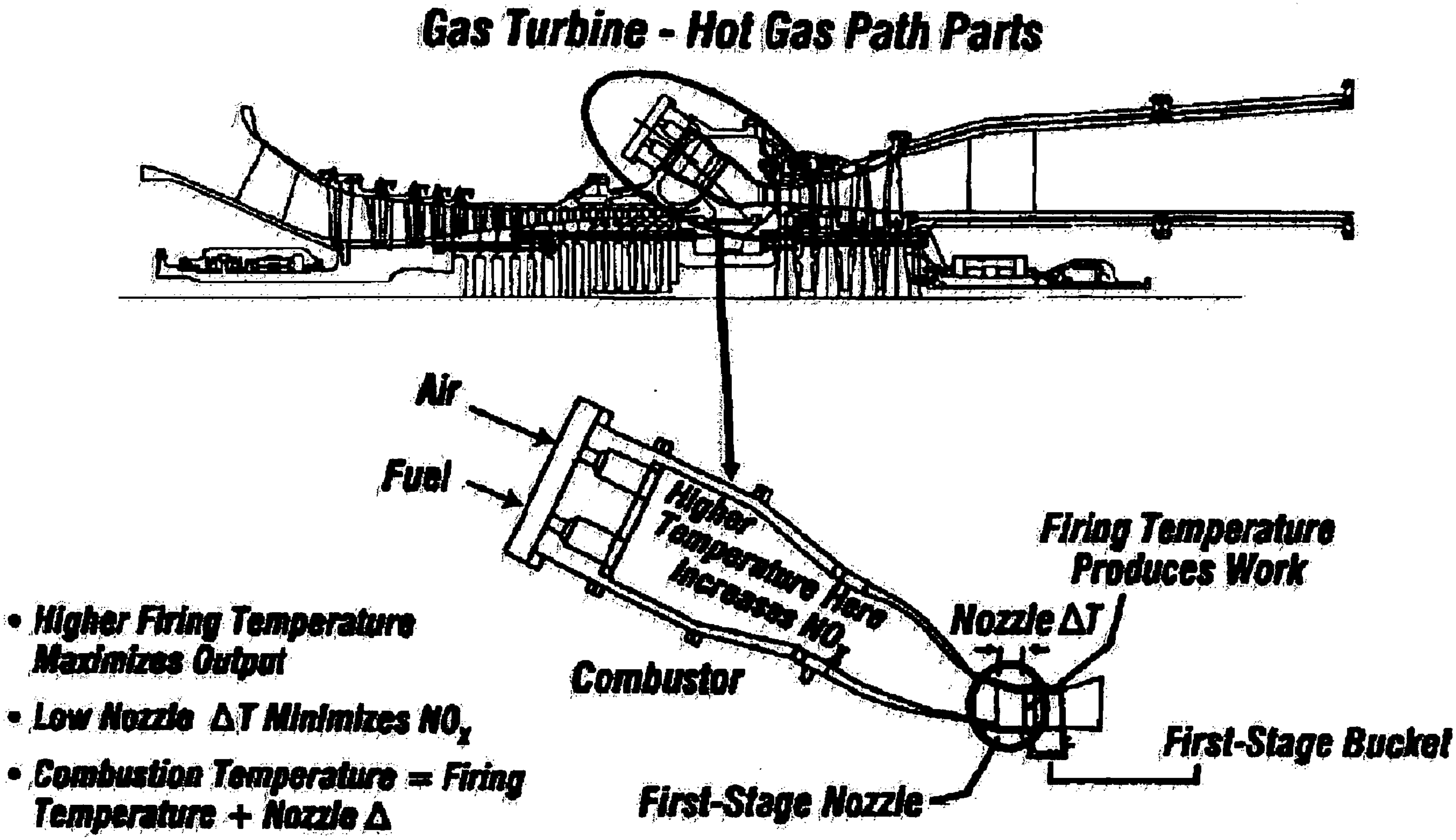
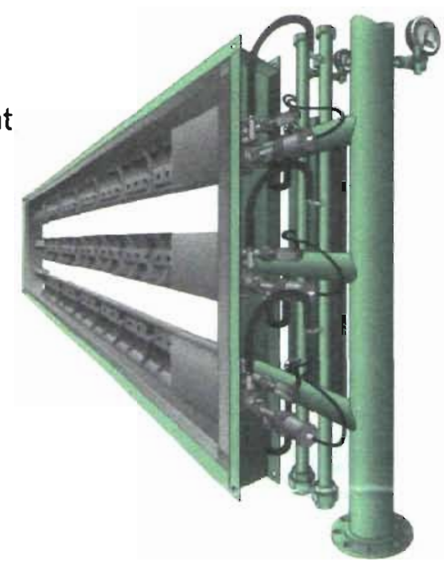
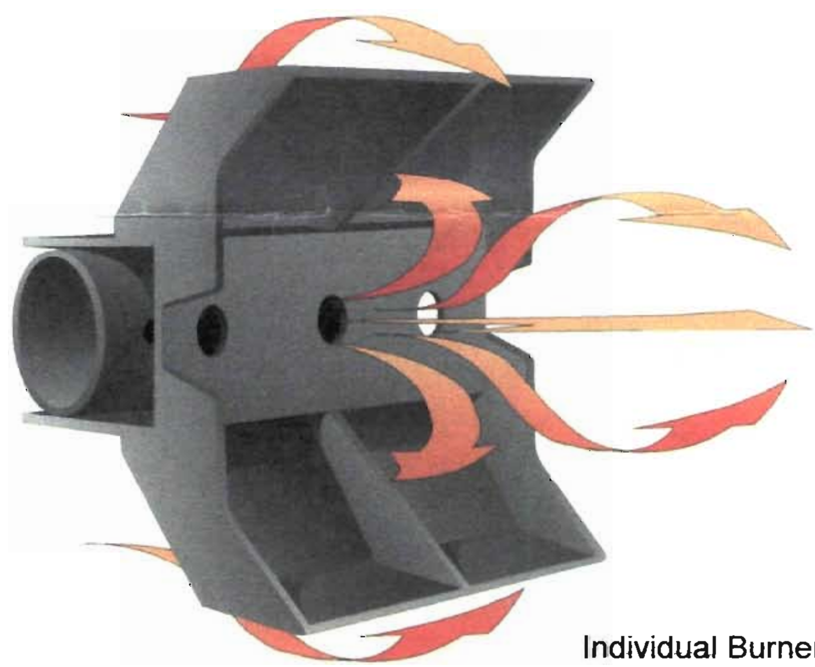


Figure 4 - Relation Between Flame Temperature and Firing Temperature

Burner Arrangment





Individual Burner

Figure 5 - Coen In-Line Gas-Fired Duct Burner

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 1130168-001-AC

Santa Rosa Energy LLC
Santa Rosa Energy Center
Santa Rosa County

Project type:

Project to install a nominal 241 megawatt (MW) combined cycle cogeneration unit at the Stirling Fibers Facility, Pace, Santa Rosa County. The unit is a nominal 167 MW General Electric MS7241FA gas-fired combustion turbine-generator with a supplementary-fired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 74 MW via a steam-driven electrical generators and provide process steam to Stirling Fibers. The project also includes: a 585 mmBtu/hr in-line gas-fired duct burner; a cooling tower; and a 200 foot stack.

Nitrogen Oxides emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen, 9 ppm of CO, and 1.4 ppm of VOC. Low NO_X burners in the in-line duct burner arrangement will operate such that NO_X emissions concentrations from the combined unit will also meet a limit of 9.8 ppm @ 15% O_2. The duct burner may not contribute more than 0.4 lb/MW-hr gross output. Combined emissions of carbon monoxide will be controlled to 24 ppm, while emissions of volatile organic compounds will be less than 8 ppm. Emissions of sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the switch to inherently clean pipeline quality natural gas. These limits meet Best Available Control Technology (BACT). If the limits are not attainable by equipment actually selected by the applicant, correspondingly lower limits must be achieved by selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR).

Impacts due to the proposed project emissions are all below the applicable significant impact limits corresponding to the nearest PSD Class I (Breton, Bradwell Bay, and St. Marks National Wilderness Areas) and Class II areas.

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

A. A. Linero, P.E.
Registration Number: 26032

10/9/98
Date

Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

A. A. LINERO
CERTIFICATE
NO. 26032
STATE OF
FLORIDA
REGISTERED ENGINEER

ATL GA 303 P/DC 20:08

Is your RETURN ADDRESS completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. Doug Neeley
Air, Radiation Tech. Branch
U S EPA - Region IV
61 Forsyth St.
Atlanta, GA 30303

4a. Article Number
Z 333 612 528

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

7. Date of Delivery
10-13-98

5. Received By: *(Print Name)*
Alan Lindsey

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

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

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 612 528

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

Sent to: Doug Neeley	
Street & Number: EPA	
Post Office, State, & ZIP Code: Atlanta, GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: 10-9-98 1130168-001-AE PSD-FI-253	

PS Form **3800**, April 1995

SANTA ROSA *ENERGY* LLC

650 Dundee Road, Suite 150
Northbrook, Illinois 60062
Telephone (847)559-9800
Facsimile (847)559-1805

RECEIVED
SEP 08 1998
BUREAU OF
AIR REGULATION

September 4, 1998
Letter No. 2

Mr. A.A. Linero
Administrator, New Source Review Section
Division of Air Resources Management
State of Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road., MS# 5505
Tallahassee, FL 32399-2400

Subject: DEP File No. 1130003-005AC (PSD-FL-253)
Santa Rosa Energy Center

Dear Mr. Linero:

Santa Rosa Energy LLC is pleased to provide the following response to your letter dated August 3, 1998 in regards to the PSD application submitted on July 8, 1998.

Although the detailed design of the cogeneration facility is not complete, the steam turbine will be sized for approximately 74 MW. Under average annual conditions, the steam turbine will operate at approximately 53 MW. The turbine will be sized for 74 MW to handle any steam swings of the steam host (Sterling Fibers, Inc.) The Santa Rosa Energy Center will ensure that the steam turbine will not exceed 75 MW through both the design and operation of the steam turbine. The steam turbine specification will clearly state that the steam turbine's maximum rated capacity will not exceed 74.5 MW. Thus, the steam turbine will not be capable of exceeding 75 MW through its design by the steam turbine manufacturer. The second means of assurance will be through the control of the steam turbine's throttle valve. The distributed control system will be programmed to control the flow of steam to the steam turbine to limit the output of the steam turbine to less than 75 MW under all scenarios. This will have the effect of controlling the operation of the steam turbine to limit the output to less than 75 MW.

Many of the comments and questions in your letter concerned the use of steam injection for power augmentation. Following a more detailed review of the steam injection system and the associated operating requirements, Santa Rosa Energy LLC is modifying its preliminary design of the cogeneration facility to exclude the steam/water injection options on the combustion turbine. This will in effect lower the emissions inventory for the facility and will require modification of our permit application. Please find attached in Exhibit A the necessary documentation to modify our permit application.

The above explanations and modifications should provide sufficient assurance that the Santa Rosa Energy Center is not a power plant as defined in the Florida Electrical Power Plant Siting Act. The Santa Rosa Energy Center will have a steam turbine that will generate less than 75 MW through both its design and operation, and there will be no additional power generated through any other steam source, such as the combustion turbine utilizing steam or water injection.

The following are responses to your specific questions and comments:

1. *Power augmentation will allow the firing of additional natural gas while injecting water/steam into the turbine, to produce more megawatts. Explain the overall operation in the power augmentation mode. What technology is used to generate extra power (i.e., steam or water injection)? How much more power output is due to operation in the power augmentation mode. Provide an schematic of the power augmentation operation mode. What is the maximum manufacturer's recommended period (hr/year, hr/month) for operation in the power augmentation mode.*

   As stated above, Santa Rosa Energy LLC is modifying its design for the Santa Rosa Energy Center. The modified design does not include steam or water injection for the combustion turbine. Santa Rosa Energy LLC is also modifying its permit application to reflect the change in design. The attached Exhibit A includes the required documentation for this modification.

2. *Does Sterling Fibers Inc. have ownership on this project or simply a contract for steam? This information will allow us to determine if the facility requires a separate identification number in our database (ARMS system).*

As the project is currently planned, Sterling Fibers, Inc. will not have an equity position in the project. The site for the Santa Rosa Energy Center will be on land that will be leased from Sterling Fibers, Inc. The supply of steam from the cogeneration system to Sterling Fibers is through a contractual relationship.

3. *Submit General Electric performance data sheets for this turbine and the HRSG's manufacturer performance sheets.*

   Please find attached as Exhibit B the performance data sheets from GE for the combustion turbine and the emissions from Coen for the duct burner in the HRSG. The HRSG vendor has not been selected yet, therefore the final performance information is not available. Estimated HRSG performance from Nooter-Eriksen, an HRSG manufacturer, has been included in Exhibit B for reference.

4. *Expand on the details (G.E. papers, etc.) of the G.E Dry Low NOx burner technology and the Mark V control system.*

   Attached as Exhibit C is GE's technical papers for both the Dry Low Nox 2.6 Combustion System and the SPEEDTRONIC Mark V Gas Turbine Control System.

5. *Provide emission calculations under the normal operating scenario (excluding the power augmentation operation mode). What is the heat rate of this project (Btu/kwh)?*

   Emission calculations for the cogeneration facility operating without power augmentation are included in our modified permit application in Exhibit A. The heat rate for similar projects of this type are typically in the range of 6,800 to 7,000 Btu/kWh.

6. *What is the total megawatts generated from steam (only)? Is the total power output capacity of the cogeneration plant 241 MW?*

   With the elimitation of steam injection, the maximum power produced from steam is limited to approximately 74 MW, with an average annual output of approximately 53

MW. The maximum rated capacity of the cogeneration facility is 250.3 MW (net) with an annual average output of 216 MW (net). The 241 MW as stated in the permit application is a nominal rating based on the annual average combustion turbine performance (167 MW) and the gross output of the steam turbine (74 MW).

7. *The Department acknowledges your request for authorization in accordance with Rule 62.210.710 F.A.C., to allow for excess emissions beyond the regulatory limit during periods of startup/shutdown and power augmentation periods. As this is the case, submit specific details about the frequency of these periods. Attach manufacturer support data.*

The existing fleet of GE 7F combustion turbines consists of more than 67 units. Of these, approximately 36 units are used in base load operation, which is similar to the planned operation of the Santa Rosa Energy Center. The fleet average for base loaded GE 7F combustion turbines is approximately 12 start/shutdown cycles per year. We expect the Santa Rosa Energy Center to have a similar start/shutdown profile of approximately 12 start/shutdown cycles per year. These cycles will normally be a result of planned maintenance, forced outages, and combustion turbine trips.

The actual start-up time for a combined cycle cogeneration facility is dependent on the length of the shut-down period. Both GE and Westinghouse classify starts into hot, warm and cold starts, each with an associated start-up curve. The start-up curves for both GE and Westinghouse for a cold start range from 210 minutes to 230 minutes. These were the times used to base our request to exceed emission limits in the permit application. Included in Exhibit D are the start-up and shutdown curves for GE and Westinghouse for combined cycle facilities similar to the Santa Rosa Energy Center.

Additionally, we are providing a response to the United States Environmental Protection Agency's letter to Mr. Clair H. Fancy of FDEP. As discussed above, Santa Rosa Energy LLC is modifying its permit application to remove the use of power augmentation. This will result in an emissions inventory based on average annual conditions from the combustion turbine. Santa Rosa Energy LLC has included in Exhibit A the emissions inventory based on these conditions. Also, we have included in Exhibit A, a supplemental cost analysis for the BACT for an SCR with a controlled Nox rate of 3.5 ppmvd. The cost analysis for oxidation catalyst for VOC and CO emissions control also has been updated and included in Exhibit A. Santa Rosa Energy LLC still considers installation of an oxidation catalyst and an SCR to be not economically feasible for the Santa Rosa Energy Center. We request that EPA's comments be assessed in light of the change in project design and the additional information supplied in this submission.

We hope that the information provided herein is in sufficient detail for you to complete your analysis of our permit application. Santa Rosa Energy LLC is eager to move forward as quickly as possible on this project. Should you have any questions or require further information, please contact me at (847)559-9800 extension 325.

Sincerely,

SANTA ROSA ENERGY LLC

Craig Carson
Project Manager

CRC:rn

Enclosures : (upon request from air)

cc: Sylvia Alderman (Katz, Kutter)
Mike Cary (Weston)

File: SRO - ENV

cc: J. Heron, BAR
C. Holladay, BAR
EPA
NPS
NWD

EXHIBIT A

- Modified Emissions Inventory

  Revised Table 3-1 - Hourly Emissions Inventory

  Revised Table 3-2 - Annual Emissions Inventory

  Revised Tables B-1 and B-2 - Sample Calculations

- Modified Control Cost Analyses

  Revised Tables 5-1 and 5-2 - VOC Catalyst

  Revised Tables 5-3 and 5-4 - CO Catalyst

  Revised Tables 5-5 and 5-6 - SCR to 3.5 ppm

- Modified Modeling

  Revised Table 6-1 - Emission Rates and Stack Parameters

  Revised Table 6-8 - Results

Exhibit A - Discussion

Santa Rosa Energy LLC has revised the emissions inventory for the Santa Rosa Energy Center to reflect elimination of the power augmentation mode of operation during natural gas firing in the combustion turbine. Without power augmentation the worst case emissions while firing natural gas will occur at 100% load. Revised Tables 3-1 and 3-2, presenting hourly and annually emissions, respectively, are enclosed along with revised sample calculations (Tables B-1 and B-2).

The control cost estimates in Section 5 (Best Available Control Technology Analysis) of the application have been updated to reflect the revised emission inventory. In addition, the tables for SCR have been further revised for costs associated with attaining a 3.5 ppm NO_x concentration in the exhaust gas stream instead of 6.0 ppm. Attached are revised Tables 5-1 and 5-2 for VOC catalyst costs, Tables 5-3 and 5-4 for CO catalyst costs, and Tables 5-5 and 5-6 for SCR costs. The conclusions reached in the original application remain unchanged, i.e., installations of oxidation catalyst for CO and VOC emissions reductions and SCR for NO_x emissions reduction are not economically feasible.

The revised emissions have been modeled. Enclosed are revised Tables 6-1 and 6-8 presenting the emissions data and modeled results, respectively. The revised modeling shows ambient impacts are insignificant. A diskette providing the revised modeling inputs and outputs is enclosed.

TABLE 3-1 (revised 26 August 1998)
SANTA ROSA ENERGY CENTER
MAXIMUM HOURLY EMISSION RATES FROM THE COGENERATION SYSTEM
COMBUSTION TURBINE AND DUCT BURNER FIRING NATURAL GAS ONLY

POLLUTANT	COMBUSTION TURBINE EMISSIONS[a] (lb/hr)	DUCT BURNER EMISSIONS[b] (lb/hr)	TOTAL STACK EMISSIONS[c][d] (lb/hr)
Total Suspended Particulate[e]	9.5	4.7	14.2
Particulate Matter <10 microns[e]	9.5	4.7	14.2
Sulfur Dioxide	1.1	0.6	1.7
Nitrogen Oxides	64.1	46.8	110.9
Volatile Organic Compounds	2.9	11.1	14.0
Carbon Monoxide	31.5	46.8	78.3
Sulfuric Acid Mist[e]	Not Available	Not Available	Not Available
Lead[f]	Not Available	2.93E-04	2.93E-04
Beryllium[f]	Not Available	7.02E-06	7.02E-06
Mercury [f]	Not Available	1.52E-04	1.52E-04
Total Organic and Inorganic HAPs[f]	Not Available	1.10	1.10

[a] Emission rates for each pollutant are the highest short-term rates over the range of ambient air conditions and load levels for the combustion turbine as provided by the combustion turbine vendor. Refer to Table B-1.

[b] Based on full load conditions firing natural gas. Refer to Table B-1.

[c] Combustion turbine with duct burner will be exhausted through a single stack.

[d] Emissions from combustion turbine/duct burner systems operating simultaneously.

[e] Sulfuric acid mist emissions are not included with particulate matter emissions. There are not separate factors available for combustion turbines or duct burners firing natural gas.

[f] AP-42 emissions factors for HAPs are not available for natural gas firing for the combustion turbine thus HAPs were assumed to be insignificant. Natural gas emission factors for natural gas combustion in boilers were used for the duct burner because of the similarity (US EPA AP-42 5th ed, Supplement D, Section 1.4). Total HAPs includes the organic and inorganic species.

TABLE 3-2 (revised 26 August 1998)
SANTA ROSA ENERGY CENTER
MAXIMUM POTENTIAL ANNUAL EMISSIONS

POLLUTANT	COMBUSTION TURBINE WITH DUCT BURNER EMISSIONS[a][b] (ton/yr)	PSD SIGNIFICANCE LEVEL[c] (ton/yr)
Total Suspended Particulate	54.7	25
Particulate Matter <10 microns	54.7	15
Sulfur Dioxide	6.4	40
Nitrogen Oxides	402.2	40
VOC	44.4	40
Carbon Monoxide	260.0	100
Sulfuric Acid Mist	Not Available	7
Lead [b]	8.20E-04	0.6
Beryllium [b]	1.97E-05	0.0004
Mercury [b]	4.26E-04	0.1
Total Organic and Inorganic HAPs [b]	3.10	-

[a] Based on hourly emissions for combustion turbine firing natural gas, i.e., at 100% load and an average annual ambient temperature of 68°F; duct burner at reduced annual average capacity firing natural gas; i.e., at 64% average annual capacity; and both operating at 8,760 hours per year. This scenario represents realistic operating conditions and provides operational flexibility.

[b] HAP emissions are presented for the duct burner only.

[c] From EPA PSD regulations, 40 CFR 52.21(b)(23)(j).

TABLE B-1 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER
POTENTIAL HOURLY EMISSION RATES FROM THE PROPOSED COGENERATION FACILITY

POLLUTANT NAME	EMISSION FACTOR (lb/MMBtu)	RATED HEAT INPUT (MMBtu/hr)	AMBIENT TEMP. (°F)	LOAD FACTOR (%)	POTENTIAL EMISSIONS (CONTROLLED)[a] (lb/hr)
COMBUSTION TURBINE					
Total Suspended Particulate	0.0051	1,847	40	100%	9.5
Particulate Matter <10 microns	0.0051	1,847	40	100%	9.5
Sulfur Dioxide	0.0006	1,847	40	100%	1.1
Nitrogen Oxides	0.0347	1,847	40	100%	64.1
Volatile Organic Compounds	0.0016	1,847	40	100%	2.9
Carbon Monoxide	0.0171	1,847	40	100%	31.5
Lead	N/D	1,847	40	100%	N/D
Sulfuric Acid Mist	N/D	1,847	40	100%	N/D
Beryllium	N/D	1,847	40	100%	N/D
DUCT BURNER					
Total Suspended Particulate	0.0080	585	(b)	100%	4.7
Particulate Matter <10 microns	0.0080	585	(b)	100%	4.7
Sulfur Dioxide	0.0010	585	(b)	100%	0.59
Nitrogen Oxides	0.0800	585	(b)	100%	46.8
Volatile Organic Compounds	0.0190	585	(b)	100%	11.1
Carbon Monoxide	0.0800	585	(b)	100%	46.8
Sulfuric Acid Mist	N/D	585	(b)	100%	N/D
Lead [c]	5.00E-07	585	(b)	100%	2.93E-04
Beryllium [c]	1.20E-08	585	(b)	100%	7.02E-06
Mercury [c]	2.60E-07	585	(b)	100%	1.52E-04
Total HAPs [c]	1.89E-03	585	(b)	100%	1.10

[a] Emission rates for each pollutant are the highest hourly rates over the range of ambient air conditions and load levels for the combustion turbines as provided by the combustion turbine vendor; for the duct burners, the hourly rate is based on operating at full capacity.

[b] Emission factors are not temperature dependent.

[c] Emission factors from US EPA AP-42, 5 th. ed. Supplement D. HHV or natural gas assumed to be 1,000 Btu/scf.
N/D indicates that emission factors are not available.

TABLE B-1 (revised 8/14/98) Continued
SANTA ROSA ENERGY CENTER
POTENTIAL HOURLY EMISSION RATES FROM THE PROPOSED COGENERATION FACILITY

HAP EMISSION FACTOR SUMMARY FOR THE DUCT BURNER

US EPA AP-42, 5 th ed, Supplement D Emission Factors (lb/10^6 scf nat gas)					
Organic Compounds			**Inorganic Compounds**		
Name of Gas Component	**Factor**	**(HAP yes/no)**	**Name of Gas Component**	**Factor**	**(HAP yes/no)**
2- Methylnaphthalene	2.40E-05	yes	Lead	0.0005	yes
2-Methylchloranthrene	1.80E-06	yes	Arsenic	2.00E-04	yes
7,12-Dimethylbenz(a)anthracene	1.60E-05	yes	Barium	4.40E-03	no
Acenaphthene	1.80E-06	yes	Beryllium	1.20E-05	yes
Acenphthracene	1.80E-06	yes	Cadmium	1.10E-03	yes
Anthracene	2.40E-06	yes	Chromium	1.40E-03	yes
Benz(a)anthracene	1.80E-06	yes	Cobalt	8.40E-05	yes
Benzene	2.10E-03	yes	Copper	8.50E-04	no
Benzo(a)pyrene	1.20E-06	yes	Manganese	3.80E-04	yes
Benzo(b)fluorthene	1.80E-06	yes	Mercury	2.60E-04	yes
Benzo(g,h,i)perylene	1.20E-06	yes	Molybdenum	1.10E-03	no
Benzo(k)fluoranthene	1.80E-06	yes	Nickel	2.10E-03	yes
Butane	2.10E+00	no	Selenium	2.40E-05	yes
Chrysene	1.80E-06	yes	Vanadium	2.30E-03	no
Dibenzo(a,h)anthracene	1.20E-06	yes	Zinc	2.90E-02	no
Dichlorobenzene	1.20E-03	yes	Total Inorganic Species	0.044	
Ethane	3.10E+00	no	Total non-HAPs	0.038	
Fluoranthene	3.00E-06	yes	Total Inorganic HAPs	0.0061	
Fluorene	2.80E-06	yes			
Formaldehyde	7.50E-02	yes	**SUMMARY**		
Hexane	1.80E+00	yes	**Total Species**	**11.33**	
Indeno(1,2,3-cd)pyrene	1.80E-06	yes	**Total non-HAPs**	**9.44**	
Naphthalene	6.10E-04	yes	**Total Inorganic HAPs**	**0.0061**	
Pentane	2.60E+00	no	**Total Volatile-HAPs**	**1.88**	
Phenanathrene	1.70E-05	yes	**Total HAPs**	**1.89**	
Propane	1.60E+00	no			
Pyrene	5.00E-06	yes			
Total Organic Species	11.28				
Total non-HAPs	9.40				
Total Volatile-HAPs	1.88				

TABLE B-2 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER
POTENTIAL ANNUAL EMISSION RATES FROM THE PROPOSED COGENERATION FACILITY
OPERATING AT 68 °F AMBIENT TEMPERATURE

POLLUTANT NAME	EMISSION FACTOR (lb/MMBtu)	EMISSION FACTOR BASIS	POTENTIAL EMISSIONS [(a)] (ton/yr)
COMBUSTION TURBINE			
Total Suspended Particulate	0.0054	(b)	41.6
Particulate Matter <10 microns	0.0054	(b)	41.6
Sulfur Dioxide	0.0006	(b)	4.8
Nitrogen Oxides	0.0349	(b)	271.0
Volatile Organic Compounds	0.0017	(b)	13.2
Carbon Monoxide	0.0166	(b)	128.8
Lead	N/D	N/D	N/D
Sulfuric Acid Mist	N/D	N/D	N/D
Beryllium	N/D	N/D	N/D
DUCT BURNER			
Total Suspended Particulate	0.0080	(c)	13.1
Particulate Matter <10 microns	0.0080	(c)	13.1
Sulfur Dioxide	0.0010	(c)	1.6
Nitrogen Oxides	0.0800	(c)	131.2
Volatile Organic Compounds	0.0190	(c)	31.2
Carbon Monoxide	0.0800	(c)	131.2
Sulfuric Acid Mist	N/D	N/D	N/D
Lead	5.00E-07	(e)	8.20E-04
Beryllium	1.20E-08	(e)	1.97E-05
Mercury	2.60E-07	(e)	4.26E-04
Total HAPs	1.89E-03	(e)	3.10

TABLE B-2 (CONTINUED)

[a] The following operating and design parameters were used in determining potential emissions from the combustion turbine and duct burner.

Combustion Turbine Parameters (Natural Gas):	
Base load (%):	100%
Capacity factor[d]:	100%
Inlet Air Temperature (°F):	68
Rated heat input (MMBtu/hr):	1,773
Annual hours of operation:	8,760
Duct Burners (Natural Gas Only):	
Capacity factor[d]:	64%
Rated heat input (MMBtu/hr):	585
Annual hours of operation:	8,760

[b] Emission factor provided by vendor performance data sheets for a combustion turbine operating at 68°F ambient temperature with a Dry Low NO_x combustor for natural gas firing.

[c] Emission factor provided by vendor for a duct burner equipped with a low NO_x burner.

[d] Factor to account for the percentage of time the unit will be in operation compared to the maximum heat input and 8,760 hours per year taking into account the variability of both heat input and hours of operation over a 12-month period.

[e] Emission factor from US EPA AP-42, 5 th. ed. Supplement D. Please see Table B-1 for emission factor summary.

N/D indicates that emission factors are not available.

SAMPLE CALCULATIONS

Emission Rates:

ton/yr = Emission factor [lb/MMBtu] x Heat input [MMBtu/hr] x Capacity factor (%) x Operating hours (hr/yr) / (2000 lb/ton)

For CO emissions from the combustion turbine during natural gas firing,

ton/yr = (0.0166 lb/MMBtu) x (1,772.8 MMBtu/hr) x (100%) x (8,760 hr/yr) / (2,000 lb/ton) = 129 ton CO/yr

TABLE 5-1 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
VOC CATALYST SYSTEM CAPITAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard VOC Catalyst System[b]	1.00 A	=	$	770,000
Instrumentation	0.10 A	=	$	77,000
Sales taxes	0.03 A	=	$	23,100
Freight	0.05 A	=	$	38,500
Purchased equipment cost, PEC	B = 1.18 A	=	$	908,600
Direct installation costs				
Foundations & supports	0.08 B	=	$	72,688
Handling & erection	0.14 B	=	$	127,204
Electrical	0.04 B	=	$	36,344
Piping	0.02 B	=	$	18,172
Insulation	0.01 B	=	$	9,086
Painting	0.01 B	=	$	9,086
Direct installation costs	0.30 B	=	$	272,580
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	1,181,180
Indirect Costs (installation)				
Engineering	0.10 B	=	$	90,860
Construction and field expenses	0.05 B	=	$	45,430
Contractor fees	0.10 B	=	$	90,860
Start-up	0.02 B	=	$	18,172
Performance test	0.01 B	=	$	9,086
Contingencies	0.03 B	=	$	27,258
Total Indirect Costs, IC	0.31 B	=	$	281,666
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	1,462,846

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 8 December 1997.

TABLE 5-2 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
VOC CATALYST SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS					COST
Direct Annual Cost, DC						
Replacement parts, catalyst (3 year life)						
Catalyst cost[a]	0.381 [b]x $ 840,000	x	1.08			$ 345,690
Spent catalyst removal cost	0.381 [b]x $ 30,000					$ 11,432
Total DC						$ 357,122
Indirect Annual Costs, IC						
Administrative charges	2% of Total Capital Investment = 0.02 ($1462846)					$ 29,257
Property tax	1% of Total Capital Investment = 0.01 ($1462846)					$ 14,628
Insurance	1% of Total Capital Investment = 0.01 ($1462846)					$ 14,628
Capital recovery[c]	0.142 [1462846 - 30000 - 840000(1.08)]					$ 74,840
Total IC						$ 133,354
Performance Penalty[f]	164.9 kW	x	8,760 hr/yr	x $ 0.04 /kW-hr[e]		$ 57,781
Total Annual Cost						$ 548,257

		capacity		
Uncontrolled VOC Emission Rate[d]	(lb/hr)	factor	(hr/yr)	(ton/yr)
Combustion Turbine (natural gas):	2.9	100%	8,760	12.7
Duct Burner (natural gas):	11.1	64%	8,760	31.1
Total Uncontrolled VOC Emission Rate, ton/yr				43.8
Estimated VOC Control Efficiency[g], %				15%
Controlled VOC Emission Rate, ton/yr				37.2
Estimated tons of VOC Controlled, ton/yr				6.6
Annual Cost per Ton VOC Controlled, $/ton				$ 83,415

[a] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[b] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[c] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142

[d] Annual emissions assuming the combustion turbine operates at 100% load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[e] Average energy cost is $0.04/kW-hr.

[f] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 164.9 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[g] 15% VOC average reduction expected for typical load conditions per vendor performance data sheet (0% - 30%).

TABLE 5-3 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
CO CATALYST SYSTEM CAPITAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard CO Catalyst System[b]	1.00 A	=	$	770,000
Instrumentation	0.10 A	=	$	77,000
Sales taxes	0.03 A	=	$	23,100
Freight	0.05 A	=	$	38,500
Purchased equipment cost, PEC	B = 1.18 A	=	$	908,600
Direct installation costs				
Foundations & supports	0.08 B	=	$	72,688
Handling & erection	0.14 B	=	$	127,204
Electrical	0.04 B	=	$	36,344
Piping	0.02 B	=	$	18,172
Insulation	0.01 B	=	$	9,086
Painting	0.01 B	=	$	9,086
Direct installation costs	0.30 B	=	$	272,580
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	1,181,180
Indirect Costs (installation)				
Engineering	0.10 B	=	$	90,860
Construction and field expenses	0.05 B	=	$	45,430
Contractor fees	0.10 B	=	$	90,860
Start-up	0.02 B	=	$	18,172
Performance test	0.01 B	=	$	9,086
Contingencies	0.03 B	=	$	27,258
Total Indirect Costs, IC	0.31 B	=	$	281,666
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	1,462,846

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 08 December 1997.

TABLE 5-4 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
CO CATALYST SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS				COST
Direct Annual Cost, DC					
Replacement parts, catalyst (3 year life)					
Catalyst cost[a]	0.381 [b]x $ 840,000	x	1.08		$ 345,690
Spent catalyst removal cost	0.381 [b]x $ 30,000				$ 11,432
Total DC					$ 357,122
Indirect Annual Costs, IC					
Administrative charges	2% of Total Capital Investment = 0.02 ($1462846)				$ 29,257
Property tax	1% of Total Capital Investment = 0.01 ($1462846)				$ 14,628
Insurance	1% of Total Capital Investment = 0.01 ($1462846)				$ 14,628
Capital recovery[c]	0.142 [1462846 - 30000 - 840000(1.08)]				$ 74,840
Total IC					$ 133,354
Performance Penalty[f]	164.9 kW	x	8,760 hr/yr	x $ 0.04 /kW-hr[e]	$ 57,781
Total Annual Cost					$ 548,257

		capacity		
Uncontrolled CO Emission Rate[d]	(lb/hr)	factor	(hr/yr)	(ton/yr)
Combustion Turbine (natural gas):	29.4	100%	8,760	128.8
Duct Burner (natural gas):	46.8	64%	8,760	131.2
Total Uncontrolled CO Emission Rate, ton/yr				260.0
Estimated CO Control Efficiency[g], %				85%
Controlled CO Emission Rate, ton/yr				39.0
Estimated tons of CO Controlled, ton/yr				221.0
Annual Cost per Ton CO Controlled, $/ton				$ 2,481

(a) The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

(b) Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

(c) The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142

(d) Annual emissions assuming the combustion turbine operates at 100% load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

(e) Average energy cost is $0.04/kW-hr.

(f) Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 164.9 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

(g) 85% CO average reduction expected for typical load conditions per vendor performance data sheet.

TABLE 5-5 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
SCR SYSTEM ANNUAL COST ESTIMATE

COST ITEM	FACTOR[a]			
Direct Costs				
Purchased equipment costs				
Engelhard SCR System[b]		=	$	1,500,000
Aqueous ammonia tank[c]		=	$	35,500
Equipment Cost	A	=	$	1,535,500
Instrumentation	0.10 A	=	$	153,550
Sales taxes	0.03 A	=	$	46,065
Freight	0.05 A	=	$	76,775
Purchased equipment cost, PEC	B = 1.18 A	=	$	1,811,890
Direct installation costs				
Foundations & supports	0.08 B	=	$	144,951
Handling & erection	0.14 B	=	$	253,665
Electrical	0.04 B	=	$	72,476
Piping	0.02 B	=	$	36,238
Insulation	0.01 B	=	$	18,119
Painting	0.01 B	=	$	18,119
Direct installation costs	0.30 B	=	$	543,567
Site preparation	As required, SP	=	$	-
Buildings	As required, Bldg.	=	$	-
Total Direct Costs, DC	1.30 B + SP + Bldg.	=	$	2,355,457
Indirect Costs (installation)				
Engineering	0.10 B	=	$	181,189
Construction and field expenses	0.05 B	=	$	90,595
Contractor fees	0.10 B	=	$	181,189
Start-up	0.02 B	=	$	36,238
Performance test	0.01 B	=	$	18,119
Contingencies	0.03 B	=	$	54,357
Total Indirect Costs, IC	0.31 B	=	$	561,686
Total Capital Investment = DC + IC	1.61 B + SP + Bldg.	=	$	2,917,143

[a] From the OAQPS Control Cost Manual, Fourth Edition, January 1990. Document number EPA 450/3-90-006.

[b] Bugetary proposal provided by Engelhard Corporation on 24 August 1998. Estimate does not include the aqueous ammonia tank.

[c] Estimated based on the size required for a 30-day supply for the combustion turbine system assuming 100% load at 68°F ambient temperature. Tank cost is estimated as $35,500 for a 22,000-gallon carbon-steel tank.

TABLE 5-6 (revised 25 August 1998)
SANTA ROSA ENERGY CENTER, MILTON, FLORIDA
SCR SYSTEM ANNUAL COST ESTIMATE

COST ITEM	CALCULATIONS	COST
Direct Annual Cost, DC		
Operating Labor		
Operator	0.5 hr/shift x 3 shift/day x 365 day/yr x \$ 25 /hr	\$ 13,688
Supervisor	15% of operator	\$ 2,053
Operating Materials		
Aqueous ammonia (28%)[a]	221.8 lb NH_3/hr x 8,760 hr/yr x \$ 0.130 /lb NH_3	\$ 252,581
Maintenance		
Labor	0.5 hr/shift x 3 shift/day x 365 day/yr x \$ 25 /hr	\$ 13,688
Material	100% of maintenance labor	\$ 13,688
Replacement parts, catalyst (3 year life)		
Catalyst cost[b]	0.381 [c]x \$ 1,000,000 x 1.08	\$ 411,536
Spent catalyst removal cost	0.381 [c]x \$ 30,000	\$ 11,432
Utility Costs		
Electricity for pump, fan, and heater[d]	129.2 kW x 8,760 hr/yr x \$ 0.04 /kW-hr[e]	\$ 45,274
Total DC		\$ 763,938
Indirect Annual Costs, IC		
Overhead	60% of sum of operating, supv., & maint. labor, & maint. materials = 0.6(13687.5 + 2053.125 + 13687.5 + 13687.5)	\$ 25,869
Administrative charges	2% of Total Capital Investment = 0.02 (\$2917143)	\$ 58,343
Property tax	1% of Total Capital Investment = 0.01 (\$2917143)	\$ 29,171
Insurance	1% of Total Capital Investment = 0.01 (\$2917143)	\$ 29,171
Capital recovery[f]	0.142 [2917143 - 30000 - 1000000(1.08)]	\$ 257,296
Total IC		\$ 399,852
Performance Penalty[g]	706.8 kW x 8,760 hr/yr x \$ 0.04 /kW-hr[e]	\$ 247,663
Total Annual Cost		\$ 1,411,452

Uncontrolled NOx Emission Rate[h]	(lb/hr)	capacity factor	(hr/yr)	(ton/yr)
Combustion Turbine (natural gas):	62.0	100%	8,760	271.6
Duct Burner (natural gas):	46.8	64%	8,760	131.2
Total Uncontrolled NOx Emission Rate, ton/yr				402.7
Estimated NOx Control Efficiency[i], %				75%
Controlled NOx Emission Rate, ton/yr				99.9
Estimated tons of NOx Controlled, ton/yr				302.9
Annual Cost per Ton NOx Controlled, \$/ton				\$ 4,660

[a] Cost based on information from Chemical Market Reporter, February 9, 1998.

[b] The 1.08 factor is for freight and sales taxes, per OAQPS Control Cost Manual.

[c] Capital recovery factor for a three year life of catalyst (vendor estimate) and a 7% interest rate (OAQPS Control Cost Manual).

[d] Per Black & Veatch Publication, 2 kW per pound of contained ammonia are required for vaporizing aqueous ammonia, and 5 kW are required to run the pump and fan. 2 kW/lb x 0.28 lb NH_3/lb x 221.8 lb/hr + 5 kW/hr = 129.2 kW/hr.

[e] Average energy cost is \$0.04/kW-hr.

[f] The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For a 10 year estimated equipment life and a 7% interest rate, CRF = 0.142.

[g] Increased pressure drop due to the installation of the catalyst will decrease combustion turbine capacity by 706.8 kW, thus causing a decrease in annual revenue. Performance penalty is incurred 8,760 hr/yr due to the presence of catalyst in the exhaust train.

[h] Annual emissions assuming the combustion turbine operates at 100% load (at 68°F ambient temperature) 8,760 hours per year firing natural gas, and conservatively assuming the duct burner operates at a 64% capacity factor 8,760 hours per year firing natural gas.

[i] 75% NO_X reduction expected for typical load conditions per vendor performance data sheet.

TABLE 6-1
STACK CHARACTERISTICS USED
TO IDENTIFY WORST-CASE LOAD CONDITIONS
SANTA ROSA ENERGY CENTER, PACE, FLORIDA

STACK CHARACTERISTIC	NATURAL GAS FIRING		
	WINTER	AVERAGE	SUMMER
Height (m)	60.96	60.96	60.96
Inside Diameter (m)[a]	5.8	5.8	5.8
100% LOAD			
Exit Velocity (m/s)	18.3	17.6	16.9
Gas Exit Temperature (K)[b]	369.0	369.0	369.0
75% LOAD			
Exit Velocity (m/s)	14.7	14.3	13.8
Gas Exit Temperature (K)[b]	365.0	365.0	365.0
65% LOAD			
Exit Velocity (m/s)	13.6	13.3	12.9
Gas Exit Temperature (K)[b]	365.0	365.0	365.0
50% LOAD			
Exit Velocity (m/s)	12.1	11.8	11.5
Gas Exit Temperature (K)[b]	364.0	364.0	364.0

[a] Inside diameter represents diameter of a single flue.

[b] Exit temperature assumed to be equal for all seasonal conditions.

TABLE 6-8
ISCST3 MODELING RESULTS FOR
SANTA ROSA ENERGY CENTER PROPOSED COGENERATION PROJECT

POLLUTANT	TOTAL MAXIMUM EMISSIONS (lb/hr)	(g/s)	MODELED MAXIMUM AMBIENT IMPACT FOR ALL RECEPTORS (μg/m³) [a] AVERAGING PERIOD 1-HR	3-HR	8-HR	24-HR	ANNUAL
100% LOAD CONDITION							
Unity Modeled Concentration $(\mu g/m^3)/(g/s)$	-----	1.00	1.9677	0.6559	0.3279	0.1415	0.00746
Total Suspended Particulates	14.2	1.79				0.25	0.01
PM10	14.2	1.79				0.25	0.01
Sulfur Dioxide	1.7	0.21		0.14		0.03	0.002
Nitrogen Oxides [c]	136.1	17.15					0.13
Carbon Monoxide [c]	99.3	12.51	24.62		4.10		
50% LOAD CONDITION [b]							
Unity Modeled Concentration $(\mu g/m^3)/(g/s)$	-----	1.00	3.6658	1.4118	0.6482	0.3093	0.01203
Total Suspended Particulates	14.2	1.79				0.55	0.02
PM10	14.2	1.79				0.55	0.02
Sulfur Dioxide	1.7	0.21		0.30		0.07	0.003
Nitrogen Oxides [c]	87.8	11.06					0.13
Carbon Monoxide [c]	67.8	8.54	31.32		5.54		

NOTES

[a] - Maximum ISCST3 modeled concentration for five-year period 1985-1989, unless otherwise indicated.
[b] - 50% load assumed for turbine only. Duct burner emissions are for 100% load.
[c] - Emission rates for winter climate conditions, which are higher than for summer conditions, were used.

Exhibit B

Vendor Performance
and
Emission Data

$4900 \frac{Btu}{Kwhr} \times .037 \frac{lb}{mm\ Btu} \times$

POLSKY ENERGY CORPORATION
ESTIMATED PERFORMANCE - PG7241(FA)

LOAD CONDITION		BASE	75%	65%	50%
AMBIENT TEMP.	- Deg F.	68	68	68	68
AMBIENT RELATIVE HUMID	- %	60	60	60	60
OUTPUT	- kW	168300.	126200.	109400.	84200.
HEAT RATE (LHV)	- Btu/kWh	9460.	10250.	10900.	12330.
HEAT CONS. (LHV) X10-6	- Btu/h	1592.1	1293.5	1192.5	1038.2
EXHAUST FLOW X10-3	- lb/h	3507.0	2884.0	2685.0	2385.0
EXHAUST TEMP	- Deg F.	1122.	1147.	1164.	1192.
EXHAUST HEAT X10-6	- Btu/h	971.8	824.8	783.5	719.1
NOX	- ppmvd @ 15% O2	9.	9.	9.	9.
NOX AS NO2	- lb/h	59.	47.	43.	37.
CO	- ppmvd	9.	9.	9.	9.
CO	- lb/h	28.	23.	22.	19.
UHC	- ppmvw	7.	7.	7.	7.
UHC	- lb/h	14.	11.	11.	9.
SO2	- ppmvw	0.	0.	0.	0.
SO2	- lb/h	1.	1.	1.	1.
SO3	- ppmvw	0.	0.	0.	0.
SO3	- lb/h	0.	0.	0.	0.
SULFUR MIST	- lb/h	0.	0.	0.	0.
PART	- lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.				
ARGON	0.88	0.89	0.88	0.88
NITROGEN	73.94	74.20	74.24	74.31
OXYGEN	12.28	12.50	12.61	12.82
CARBON DIOXIDE	3.96	3.88	3.83	3.73
WATER	8.94	8.54	8.44	8.26

SITE CONDITIONS
****

ELEVATION	- ft.	60
SITE PRESSURE	- psia	14.67
INLET LOSS	- in. Water	4.5
EXHAUST LOSS	- in. Water	12
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20431
APPLICATION	-	7FH2 HYDROGEN-COOLED GENERATOR
COMBUSTION SYSTEM	-	9/42 DLN COMBUSTOR

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE
NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.
THE FUEL HAS .2GRAINS/100SCF OF SULFUR.
THIS PERFORMANCE INCLUDES THE EFFECTS OF AN 85 % EFFECTIVE EVAPORATIVE COOLER.
THE COOLER IS TURNED ON FOR BASE LOAD ONLY.

IPS-70447 POLSKY7F version code-0597D-0597E-0597D-0 N
JBS 06-Nov-97 09:41 AM

Androscoggin /DB

COEN Company, Inc.
Leaders in Combustion Technology

1510 Rollins Road
Burlingame, CA 94010
Phone: (415) 697-0440
Fax: (415) 579-3255

from Burlingame Division

Date:	January 10, 1997	**No. of Pages:**	1
Company:	Polsky Energy Corporation	**From:**	Rick Fiorenza
Attention:	Mr. Bryan E. Schueler *Phone:* 847/559-9800 *Fax:* 847/559-1805	**Project:**	Androscoggin Energy Center (formely WEPCO 40D-11842-1)

Dear Bryan,

In response to your January 2, 1997 letter to Coen requesting us to review the current duct burner emissions levels for the proposed Androscoggin Energy Center project please note:

Coen is able to guarantee the duct burner emissions levels as stated below:

> Emissions are based upon the duct burner firing natural gas only (at maximum design capacity) and TEG conditions specified in your Jan. 2 letter.
>
> **Burner Heat Release:** 274 mmBTU/hr (net LHV)
> 304 mmBTU/hr (gross HHV)

NOx	0.080 lb/mmBTU	24.32 lb/hr
CO	0.080 lb/mmBTU	24.32 lb/hr
SO2	0.001 lb/mmBTU	0.30 lb/hr
VOC	0.019 lb/mmBTU	5.78 lb/hr
Part.	0.008 lb/mmBTU	2.43 lb/hr

* At lower firing rates the duct burner emission rates as stated in "lb/mmBTU" will vary; however during operation below capacity, the duct burner emissions will never exceed rates stated in "lb/hr" above.

In addition, Coen recommends a formal review of the entire system to optimize the operation for natural gas firing prior to commissioning the duct burners. We invision minor logic and equipment changes will be necessary and can be formally addressed at the appropriate time.

I hope the above information is helpful to your efforts as we look forward to working with you in the near future.

Sincerely,

Rick Fiorenza

Rick Fiorenza
Manager, Energy Systems

cc. Dave Noll, N/E
file: Document2

01/10/97 11:38 AM

NE NOOTER/ERIKSEN

PROPOSAL

Prop No. 809-03
September 3, 1998

Polsky Energy Corporation
850 Dundee Road, Suite 150
Northbrook, IL 60062

Attention: Joel Schroeder, Project Engineer (Fax # 847-559-1805)

Reference: Combined Cycle Project for Florida
One (1) GE Frame 7FA HRSG

ANY ACCEPTANCE OF THIS QUOTE SHALL CONSTITUTE AN ACCEPTANCE OF ALL THE TERMS AND CONDITIONS CONTAINED ON THE FRONT AND REVERSE SIDE OF THIS QUOTATION. PLEASE READ THEM CAREFULLY.

Gentlemen:

In reply to your RFQ e-mailed to us on September 2nd, 1998, for the above referenced project, we offer the following information for your review.

The budget price to design and supply one (1) fired, triple pressure level GE Frame 7FA HRSG is: ....

Estimated weight: .... 4,500,000 lbs.

Ex-works

This HRSG will be designed and fabricated in accordance with Section I of the ASME Boiler and Pressure Vessel Code.

The scope of supply of the HRSG is essentially complete from the combustion turbine outlet flange through the exhaust stack including all of the required pressure parts necessary to generate the desired steam production, natural gas only fired duct burner, interconnecting ASME Section I Code piping local to the boiler, boiler trim, ladders, platforms, and stairtower.

<u>Options</u>

1. The budget price add for freight to the nearest rail siding (for rail shipments) or plant gate (for truck shipments) is: ....

Performance Data

We have performed a preliminary heat balance to confirm that the HP, IP, and LP unfired steam performance requested in your RFQ can be met. The approximate unfired steam production is as follows:

- 510,000 pph of 1000°F HP Steam at 1450 psig
- 44,000 pph of 850°F IP Steam at 635 psig
- 57,000 pph of 400°F LP Steam at 75 psig
- 75,000 pph of 320°F Saturated Steam for Deaeration

We have assumed a "standard" static gas side pressure drop through the HRSG of 12" w.c. As the project evolves and more information becomes available, this and other data (i.e. expected steam production at part load CT operation, sliding pressure envelope, fired steam production demands, etc.) will need to be provided in order for us to provide a more definitive design and price.

Comments

1. The RFQ did not address silencing criteria. If available, please provide combustion turbine sound power levels and near field and far field noise requirements and we will review our offering to determine if noise attenuation devices are required.

2. A simple cycle bypass system was not requested and is not included in our price.

3. Per your request, our pricing includes a natural gas fired only duct burner. The performance information outlined above is based on the unfired steam production from the HRSG. Fired HP, IP and LP steam production demands will eventually need to be provided to us so we can design for the fired case.

Commercial

Progress payments keyed into major milestone dates will be required. Terms of payment are net thirty (30) days after invoice date.

Sales, use, gross receipts, excise, value added, and other taxes are not included and shall be paid direct to the proper taxing authorities by the purchaser or owner.

If the project is not near term it would be prudent to escalate our price .33% per month after December 31st, 1998 in order to cover increases in shop wages and raw material costs.

Due to the busy market conditions all of us in the power business are currently experiencing, drawing and document submittal lead times (i.e. General Arrangement Drawings, Foundation Loading Diagram, Foundation Base Plate Details, P&ID, etc.) are around fourteen to sixteen (14-16) weeks after receipt of an order and full release.

Again, due to the current market conditions, lead-time for equipment delivery is longer than it has been for several years. Based on current conditions, equipment deliveries can commence starting eleven to twelve (11-12) months after receipt of an order and complete three to four (3-4) months later. Please factor these lead times into your schedule for the project.

If you have any questions, please do not hesitate to contact Tony Hanlin (thermal design) or me.

Yours very truly,
Nooter\Eriksen, Inc.

Michael D. Grimm

Michael D. Grimm
Sales Engineer

cc: Tony Hanlin @ N/E
Power Technology Services

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Exhibit C

DLN 2.6 and Mark V Control

System Technical Information

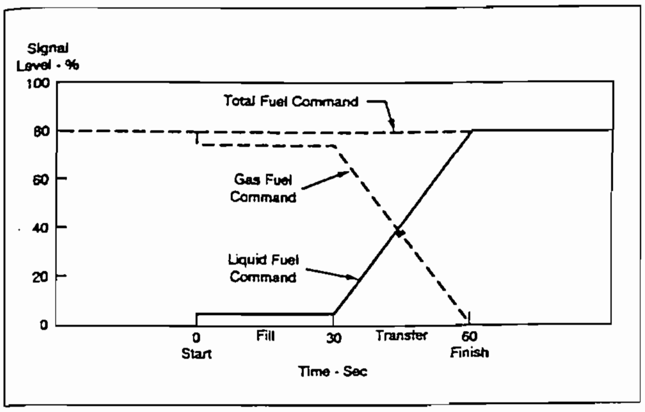

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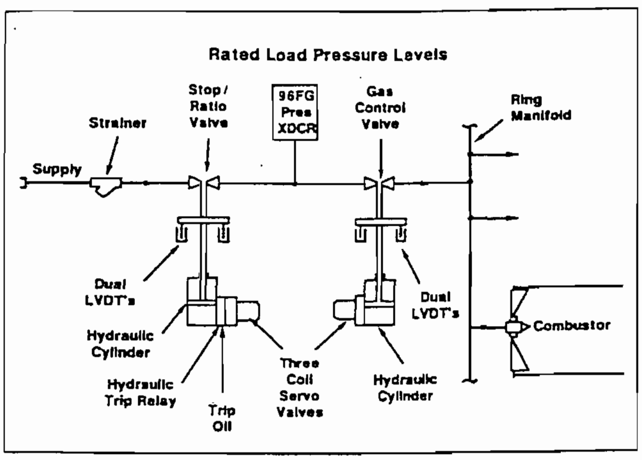
Figure 3. Dual fuel transfer characteristics gas to liquid



GT17599

Figure 4. Fuel gas control system

The liquid fuel control system is shown schematically in Fig. 5. Since the fuel pump is a positive displacement pump, the system achieves flow control by recirculating excess fuel from the discharge back to the pump suction. The required turn-down ratio is achieved by multiplying the fuel command by a signal proportional to turbine speed. The resultant signal positions the pump recirculation, or bypass valve, as appropriate to make the actual fuel flow, as measured by the speed of the liquid fuel flow divider, equal the product of turbine speed and fuel command. This approach assures a system in which both the liquid and gas fuel commands are essentially equal. Fuel distribution to the liquid fuel nozzles in the multiple combustors is achieved via the flow divider. This is a proven mechanical device which consists of carefully matched gear pumps for each combustor, all of which are mechanically connected to run at the same speed.

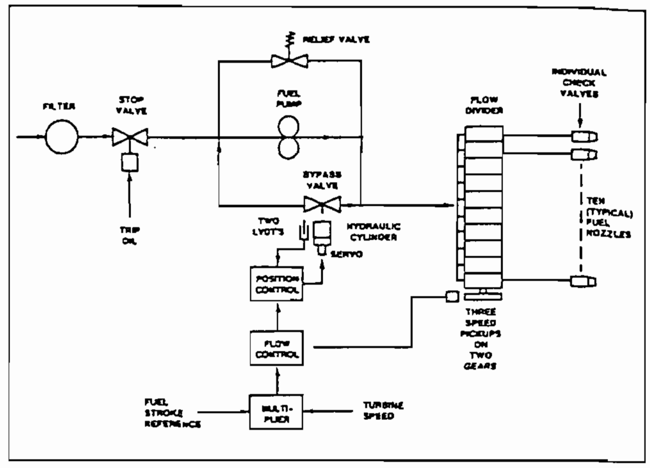


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Figure 5. Liquid fuel control system

Control of nitrogen oxide emissions may be accomplished by the injection of water or steam into the combustors. The amount of water required is a function of the fuel flow, the fuel type, the ambient humidity, and nitrogen oxide emissions levels required by the regulations in force at the turbine site. Steam flow requirements are generally about 40% higher than the equivalent water flow, but have a more beneficial effect on turbine performance. Accuracy of the flow measurement, control system, and system monitoring meets or exceeds both EPA and all local code requirements. An independent, fast-acting shutoff valve is provided to ensure against loss of flame due to over-watering on sudden load rejection.

Control of emissions utilizing dry low NO_x combustion techniques relies on multiple combustion staging to optimize fuel/air ratios and achieve thorough premixing in various combinations, depending on desired operating temperature. The emissions fuel control system regulates the division of fuel among the multiple-combustion stages according to a schedule which is determined by a calculated value of the combustion reference temperature. The control system also monitors actual combustion system operation to ensure compliance with the required schedule. Special provisions are incorporated to accommodate off-normal situations such as load rejection.

The gas turbine, like any internal combustion engine, is not self starting and requires an outside source of cranking power for start-up. This is usually a diesel engine or electric motor combined with a torque converter, but could also be a steam turbine or gas expander if external steam or gas supplies are available. Start-up via the generator, using variable frequency power supplies, is used on some of the larger gas turbines. Sufficient cranking power is provided to crank the unfired gas turbine at 25 to 30% speed, depending on the ambient temperature, even though ignition speed is 10 to 15%. This extra cranking power is used for gas path purging prior to ignition, for compressor water washing, and for accelerated cool-down.

A typical automatic starting sequence is shown in Fig. 6. After automatic system checks have been successfully completed and lube oil pressure established, the cranking device is started, and for diesel engines, allowed to warm up. Simple-cycle gas turbines with conventional upward exhausts do not require purging prior to ignition, and the ignition sequence can proceed as the rotor speed passes through firing speed. If ignition does not occur before the sixty second cross firing timer times out, the controls will automatically enter a purge sequence, as described later, and then attempt to refire.

However, if there is heat recovery equipment, or if the exhaust ducting has pockets where combustibles can collect, gas path purging is used to ensure a safe light-off. When the turbine reaches purge speed, this speed is held for the necessary purge period, usually sufficient to ensure three to five volume changes in the gas path. Purge times will vary from one minute to as long as ten minutes in some heat recovery applications. When purging is completed, the turbine rotor is allowed to decelerate to ignition speed. This speed has been found to be optimum from the standpoint of both thermal fatigue duty on the hot gas path components, as well as offering reliable ignition and cross firing of the combustors.

The ignition sequence consists of turning on ignition power to the spark plugs and then setting firing fuel flow. When flame is detected by the flame detectors, which are on the opposite side of the turbine from the spark plugs, ignition and cross firing are complete. Fuel is reduced to the warm-up value for one minute, and the starting device power is brought to maximum. If successful ignition and cross firing are not achieved within an appropriate period of time, the control system automatically reverts back to the purge sequence, and will attempt a second firing sequence without operator intervention. In the unlikely event of incomplete cross firing, it will be detected by the combustion monitor as a high exhaust temperature spread prior to loading the gas turbine.

After completion of the warm-up period, fuel flow is allowed to increase, and the gas turbine begins to accelerate faster. At a speed of about 30 to 50%, the gas turbine enters a predeter-

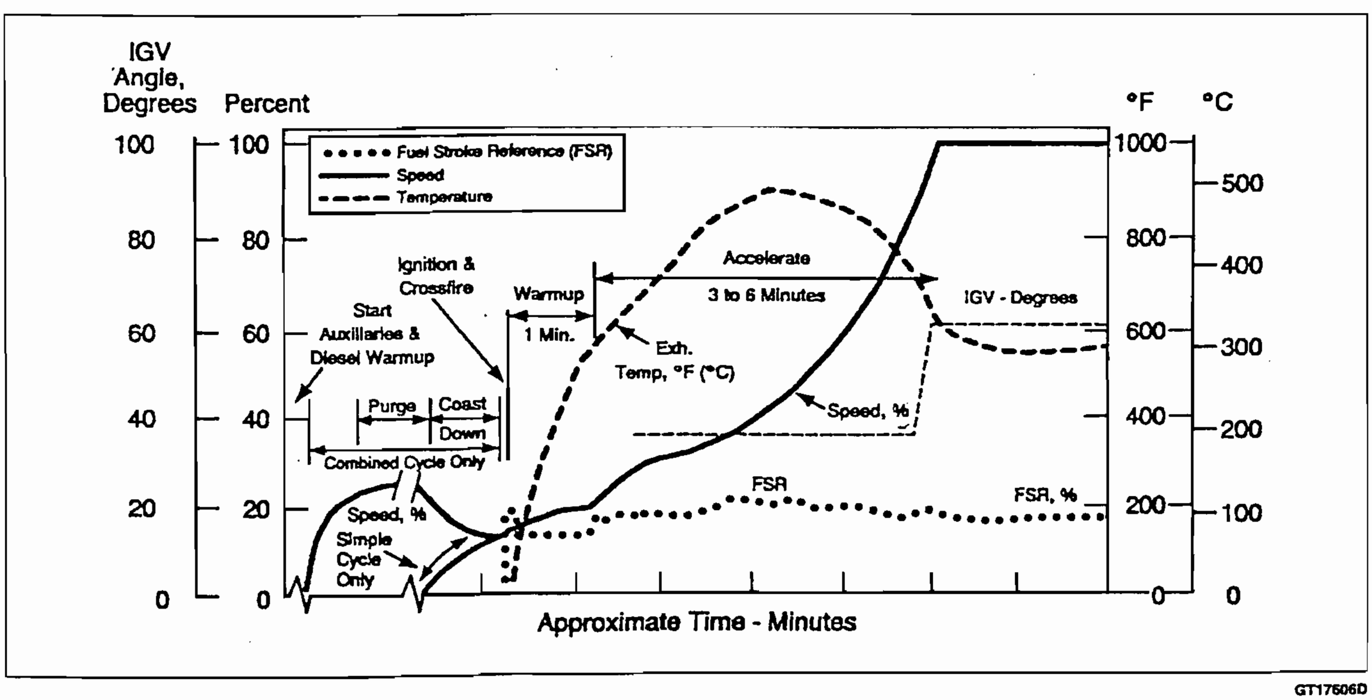

Figure 6. Typical gas turbine starting characteristics

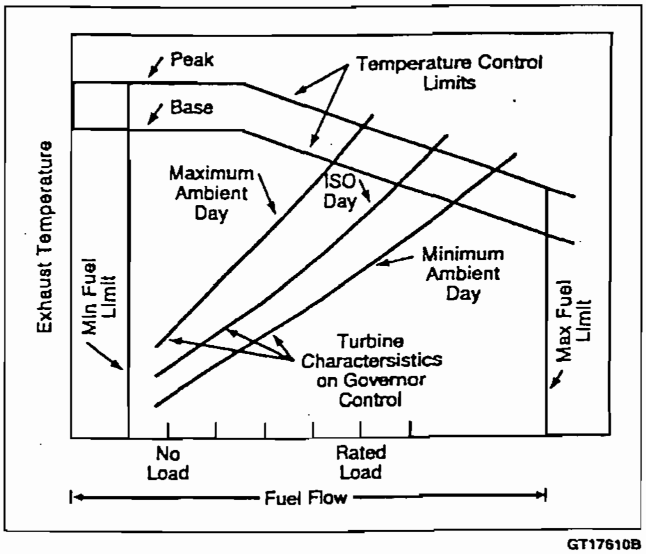

Figure 1. Gas turbine generator controls and limits

systems is shown in Fig. 2. The input to the system is the operator command for speed (when separated from the grid) or load (when connected). The outputs are the commands to the gas and liquid fuel control systems, the inlet guide vane positioning system and the emissions control system. A more detailed discussion of the control functionality required by the gas turbine may be found in Reference 1.

The fuel command signal is passed to the gas and liquid fuel systems via the fuel signal divider, in accordance with the operator's fuel selection. Start-up can be on either fuel, and transfers under load are accomplished by transitioning from one system to the other after an appropriate fill time to minimize load excursions. System characteristics during a transfer from gas to liquid fuel are illustrated in Fig. 3. Purging of the idle fuel system is automatic and continuously monitored to ensure proper operation. Transfer can be automatically initiated on loss of supply of the running fuel, which will be alarmed, and will proceed to completion without operator intervention. Return to the original fuel is manually initiated.

The gas fuel control system is shown schematically in Fig. 4. It is a two-stage system, incorporating a pressure control proportional to speed and a flow control proportional to fuel command. Two stages provide a stable turn-down ratio in excess of one-hundred-to-one, which is more than adequate for control under starting and warm-up conditions, as well as maximum flow for peak output at minimum ambient temperature. The stop/speed ratio valve also acts as an independent stop valve. It is equipped with an interposed, hydraulically-actuated trip relay which can trip the valve closed independent of control signals to the servo valve. Both the stop/ratio and control valves are hydraulically-actuated, single-acting valves that will fail to the closed position on loss of either signal or hydraulic pressure. Fuel distribution to the gas fuel nozzles in the multiple combustors is accomplished by a ring manifold in conjunction with careful control of fuel nozzle flow areas.

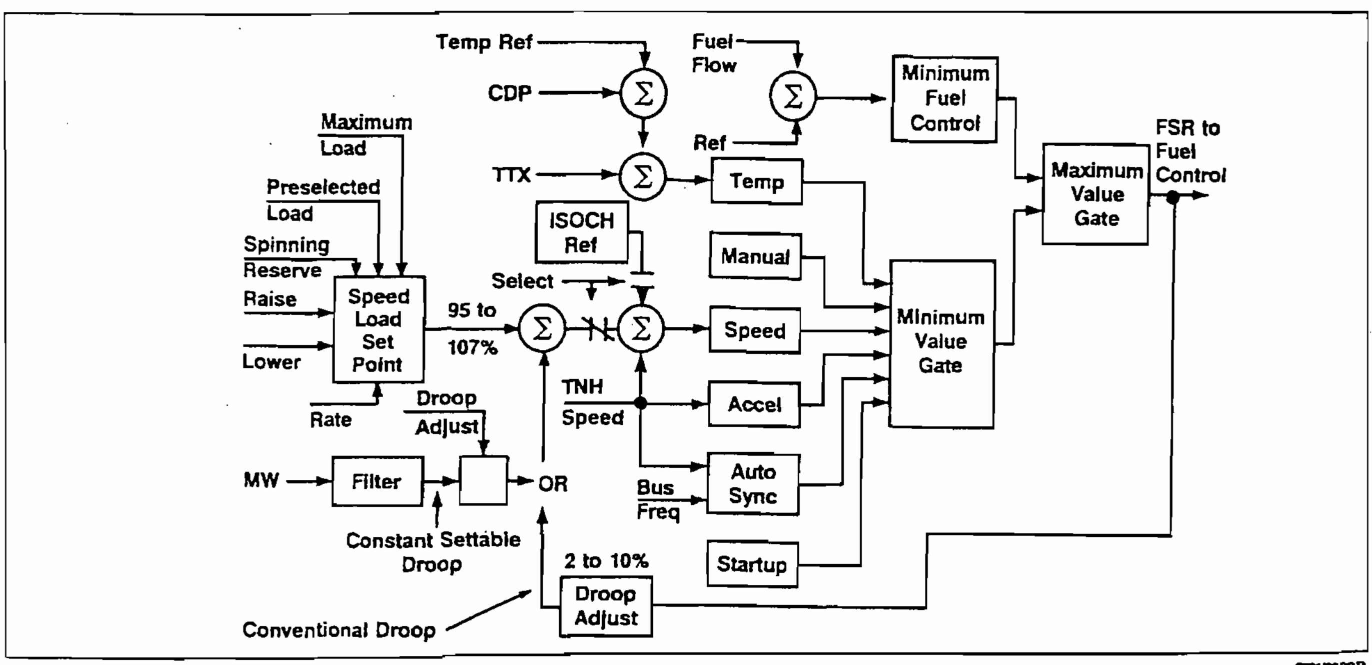

Figure 2. Gas turbine fuel control

Table 1
ADVANCES IN ELECTRONIC CONTROL CONCEPTS

System Type	Mark I	Mark II	Mark II ITS	Mark IV	Mark V
Introduced	1966	1973	1976	1982	1991
Total Shipped	850	1825	356	1080	530
Sequencing	Relays	Discrete Solid State Components		TMR Micro-processor	TMR Micro-processor
Control	Discrete Solid State	Inte-grated Circuits	I.C.s & Micro-processor	TMR Micro-processor	TMR Micro-processor
Protection	Relays	Relays & Solid State	I.C.s & Micro-processor	TMR Micro-processor	Independent TMR Micro-processor
Display	Analog Meters & Relay Annunciator	Analog and Digital Meters; Solid State Annunciator		CRT & LED Aux. Display	VGA Color Graphics
Input	Pushbuttons and Bat Handle Switches			Membrane Switches	Keyboard and/or CPD
Fault Tolerance	Manually Rejectable Failed Exhaust Thermocouples		Automatically Rejected Failed T.C.s	Hardware-based	SIFT

years of gas turbine control experience has involved more than 5,400 units, while the twenty-six years of electronic control experience has been centered on more than 4,400 turbine installations. Throughout this time period, the control philosophy shown in Table 2 has developed and matured to match the capabilities of the existing technology. This philosophy emphasizes safety of operation, reliability, flexibility, maintainability, and ease of use, in that order.

Table 2
GAS TURBINE CONTROL PHILOSOPHY

- SINGLE CONTROL FAILURE ALARMS WHEN RUNNING OR DURING START-UP
- PROTECTION BACKS UP CONTROL, THUS INDEPENDENT PROTECTIVE FAILURE WILL CAUSE SHUTDOWN
- TWO INDEPENDENT MEANS OF SHUTDOWN SHALL BE AVAILABLE
- DOUBLE FAILURE MAY CAUSE SHUTDOWN, BUT WILL ALWAYS RESULT IN SAFE SHUTDOWN
- GENERATOR DRIVE TURBINES WILL TOLERATE FULL LOAD REJECTION WITHOUT OVERSPEEDING
- CRITICAL SENSORS ARE REDUNDANT
- CONTROL IS REDUNDANT
- ALARM ANY CONTROL SYSTEM PROBLEMS
- STANDARDIZE HARDWARE AND SOFTWARE TO ENHANCE RELIABILITY WHILE MAINTAINING FLEXIBILITY

CONTROL SYSTEM FUNCTIONS

The SPEEDTRONIC™ Gas Turbine Control System performs many functions including fuel, air, and emissions control; sequencing of turbine fuel and auxiliaries for start-up, shutdown, and cool-down; synchronization and voltage matching of the generator and system; monitoring of all turbine, control and auxiliary functions; and protection against unsafe and adverse operating conditions. All of these functions are performed in an integrated manner which is tailored to achieve the previously described philosophy in the stated priority.

The speed and load control function acts to control the fuel flow under part-load conditions to satisfy the needs of the governor. Temperature control limits fuel flow to a maximum consistent with achieving rated firing temperatures, and controls air flow via the inlet guide vanes to optimize part-load heat rates on heat recovery applications. The operating limits of the fuel control are shown in Fig. 1. A block diagram of the fuel, air and emissions control panel and sensor faults. These faults are identified down to the board level for the panel and to the circuit level for the sensor or actuator components. The ability for on-line replacement of boards is built into the panel design, and is available for those turbine sensors where physical access and system isolation are feasible. Set points, tuning parameters, and control constants are adjustable during operation using a security password system to prevent unauthorized access. Minor modifications to sequencing and the addition of relatively simple algorithms can be accomplished when the turbine is not operating. They are also protected by a security password.

A printer is included in the control system and is connected via the operator interface. The printer is capable of copying any alpha-numeric display shown on the monitor. One of these displays is an operator configurable demand display that can be automatically printed at a selectable interval. It provides an easy means to obtain periodic and shift logs. The printer automatically logs time-tagged alarms, as well as the clearance of alarms. In addition, the printer will print the historical trip log that is frozen in memory in the unlikely event of a protective trip. The log assists in identifying the cause of a trip for trouble shooting purposes.

The statistical measures of reliability and availability for SPEEDTRONIC™ Mark V systems have quickly established the effectiveness of the new control because it builds on the highly successful SPEEDTRONIC™ Mark IV system. Improvements in the new design have been made in microprocessors, I/O capacity, SIFT technology, diagnostics, standardization, and operator information, along with continued application flexibility and careful design for maintainability. SPEEDTRONIC™ Mark V control is achieving greater reliability, faster mean-time-to repair, and improved control system availability than the SPEEDTRONIC™ Mark IV applications.

As of May 1994, almost 264 Mark V systems had entered commercial service, and system operation has exceeded 1.4 million hours. The established Mark V level of system reliability, including sensors and actuators, exceeds 99.9 percent, and the fleet mean-time-between-forced-outages (MTBFO), stands at 28,000 hours. As of May 1994, there were 424 gas turbine Mark V systems and 106 steam turbine Mark V systems shipped or on order.

CONTROL SYSTEM HISTORY

The gas turbine was introduced as an industrial and utility prime mover in the late 1940s, with initial applications in gas pipeline pumping and utility peaking. The early control systems were based on hydro-mechanical steam turbine governing practice, supplemented by a pneumatic temperature control, preset start-up fuel limiting, and essentially manual sequencing. Independent devices provided protection against overspeed, overtemperature, fire, loss of flame, loss of lube oil, and high vibration.

Through the early years of the industry, gas turbine control designs benefited from the rapid growth in the field of control technology. The hydro-mechanical design culminated in the "Fuel Regulator" and automatic relay sequencing for automatic start-up, shutdown, and cool-down, where appropriate for unattended installations. The automatic relay sequencing, in combination with rudimentary annunciator monitoring, also allowed interfacing with SCADA (Supervisory Control And Data Acquisition) systems for true continuous remote control operation.

This was the basis for introduction of the first electronic gas turbine control in 1968. This system, ultimately known as the SPEEDTRONIC™ Mark I Control, replaced the fuel regulator, pneumatic temperature control, and electro-mechanical starting fuel control with an electronic equivalent. The automatic relay sequencing was retained, and the independent protective functions were upgraded with electronic equivalents where appropriate. Because of its electrically dependent nature, emphasis was placed on integrity of the power supply system, leading to a DC - based system with AC - and shaft-powered backups. These early electronic systems provided an order of magnitude increase in running reliability and maintainability.

Once the change-over to electronics was achieved, the rapid advances in electronic system technology resulted in similar advances in gas turbine control technology, which is illustrated in Table 1. It should be noted that over forty

SPEEDTRONIC™ MARK V GAS TURBINE CONTROL SYSTEM

W.I. Rowen
GE Industrial & Power Systems
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OVERVIEW

The SPEEDTRONIC™ Mark V Gas Turbine Control System is the latest derivative in the highly successful SPEEDTRONIC™ series. Preceding systems were based on automated turbine control, protection, and sequencing techniques dating back to the late 1940s, and have grown and developed with the available technology. Implementation of electronic turbine control, protection, and sequencing originated with the Mark I system in 1968. The Mark V system is a digital implementation of the turbine automation techniques learned and refined in more than 40 years of successful experience, over 80% of which has been through the use of electronic control technology.

The SPEEDTRONIC™ Mark V Gas Turbine Control System employs current state-of-the-art technology, including triple redundant sixteen-bit microprocessor controllers, two-out-of-three voting redundancy on critical control and protection parameters, and Software Implemented Fault Tolerance (SIFT). Critical control and protection sensors are triple redundant and voted by all three control processors. System output signals are voted at the contact level for critical solenoids, at the logic level for the remaining contact outputs, and at three coil servo valves for analog control signals, thus maximizing both protective and running reliability. An independent protective module provides triple redundant hard-wired detection and shutdown on overspeed along with detecting flame. This module also synchronizes the turbine generator to the power system. Synchronization is backed up by a check function in the three control processors.

The Mark V Control System is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. In addition, inlet guide vanes and water or steam injection are controlled to meet emissions and operating requirements. If emissions control utilizes dry low NO_x techniques, fuel staging and combustion mode are controlled by the Mark V system, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V Control System. Turbine protection against adverse operating situations and annunciation of abnormal conditions are incorporated into the basic system.

The operator interface consists of a color graphic monitor and keyboard to provide feedback regarding current operating conditions. Input commands from the operator are entered using a cursor positioning device. An arm/execute sequence is used to prevent inadvertent turbine operation. Communication between the operator interface and the turbine control is through the Common Data Processor, or <C>, to the three control processors called <R>, <S>, and <T>. The operator interface also handles communication functions with remote and external devices. An optional arrangement, using a redundant operator interface, is available for those applications where integrity of the external data link is considered essential to continued plant operations. SIFT technology protects against module failure and propagation of data errors. A panel mounted back-up operator display, directly connected to the control processors, is provided to allow continued gas turbine operation in the unlikely event of a failure of the primary operator interface or the <C> module.

Built-in diagnostics for trouble-shooting purposes are extensive, and include "power-up", background and manually initiated diagnostic routines capable of identifying both control

GER-3658D

GE Power Generation

SPEEDTRONIC™ Mark V
Gas Turbine Control System

W.I. Rowen
GE Industrial & Power Systems
Schenectady, NY

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6.1.1.7 Flame Detection

Reliable detection of the flame location in the DLN-2.6 system is critical to the control of the combustion process and to the protection of the gas turbine hardware. Four flame detectors in separate combustion chambers around the gas turbine are mounted to detect flame in all modes of operation. The signals from these flame detectors are processed in control logic and used for various control and protection functions.

6.1.1.8 Ignition System

Two spark plugs located in different combustion chambers are used to ignite fuel flow. These spark plugs are energized to ignite fuel during start-up only, at firing speed. Flame is propagated to those combustion chambers without spark plugs through crossfire tubes that connect adjacent combustion chambers around the gas turbine.

6.1.1.5 DLN-2.6 Inlet Guide Vane Operation

The DLN-2.6 combustor emission performance is sensitive to changes in fuel to air ratio. The combustor was designed according to the airflow regulation scheme used with inlet guide vane, (IGV), temperature control. Optimal combustor operation is crucially dependent upon proper operation along the predetermined temperature control scheme. Controlled fuel scheduling will be dependent upon the state of IGV temperature control. IGV temperature control on can also be referred to as combined cycle operation while IGV temperature control off is referred to as simple cycle operation.

6.1.1.6 DLN-2.6 Inlet Bleed Heat

Operation of the gas turbine with reduced minimum IGV settings can be used to extend the Premix operating region. Reducing the minimum IGV angle allows the combustor to operate at a firing temperature high enough to achieve optimal emissions.

Inlet bleed heating, (IBH), through the use of recirculated compressor discharge airflow, is necessary when operating with reduced IGV angles. Inlet heating protects the compressor from stall by relieving the discharge pressure and by increasing the inlet air stream temperature. Other benefits include anti-icing protection due to increased pressure drop across the IGV's.

The inlet bleed heat system regulates compressor discharge bleed flow through a control valve and into a manifold located in the compressor inlet air stream. The control valve varies the inlet heating air flow as a function of IGV angle. At minimum IGV angles the inlet bleed flow is controlled to a maximum of 5.0% of the total compressor discharge flow. As the IGV's are opened at higher loads, the inlet bleed flow will proportionally decrease until shut off.

The IBH control valve is monitored for its ability to track the command setpoint. If the valve command setpoint differs from the actual valve position by a prescribed amount for a period of time, an alarm will annunciate to warn the operator. If the condition persist for an additional amount of time, the inlet bleed heat system will be tripped and the IGV's minimum reference will be raised to the default value.

The IBH system monitors the temperature rise in the compressor inlet airflow. This temperature rise serves as an indication of bleed flow. Failure to detect a sufficient temperature rise in a set amount of time will cause the inlet bleed heat system to be tripped and an alarm annunciated.

The fuel flow to the six fuel nozzles and quaternary pegs are controlled by four independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one, (PM1), gas control valve two (PM2), gas control valve three, (PM3), and gas control valve four, (Quat).

The stop/ratio valve (SRV) is designed to maintain a predetermined pressure, (P2), at the inlet of the gas control valves. Gas control valves one through four, (GCV1-4), regulate the desired gas fuel flow delivered to the turbine in response to the command signal FSR, (Fuel Stroke Reference), from the SPEEDTRONIC panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. This flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software.

6.1.1.3 Gas Fuel Operation

The DLN 2.6 fuel system operation is fully automated, sequencing the combustion system through a number of staging modes prior to reaching full load. The primary controlling parameter for fuel staging is the calculated combustion reference temperature (TTRF1).Other DLN 2.6 operation influencing parameters available to the operator are the selection of IGV temperature control "on" or "off", and the selection of inlet bleed heat "on" or "off". To achieve maximum exhaust temperature as well as an expanded load range for optimal emission, IGV temperature control should be selected "ON", and inlet bleed heat should be selected "ON". Temperature control and Inlet bleed heat operation will be discussed later in this document.

6.1.1.4 Chamber arrangement

The 7F gas turbine employs 14 combustors. There are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent combustors. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi-nozzle cap assembly, liner assembly, and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion can, porting fuel to casing injection pegs located radially around the casing.

6.1.1 Dry Low Nox 2.6 Combustion System

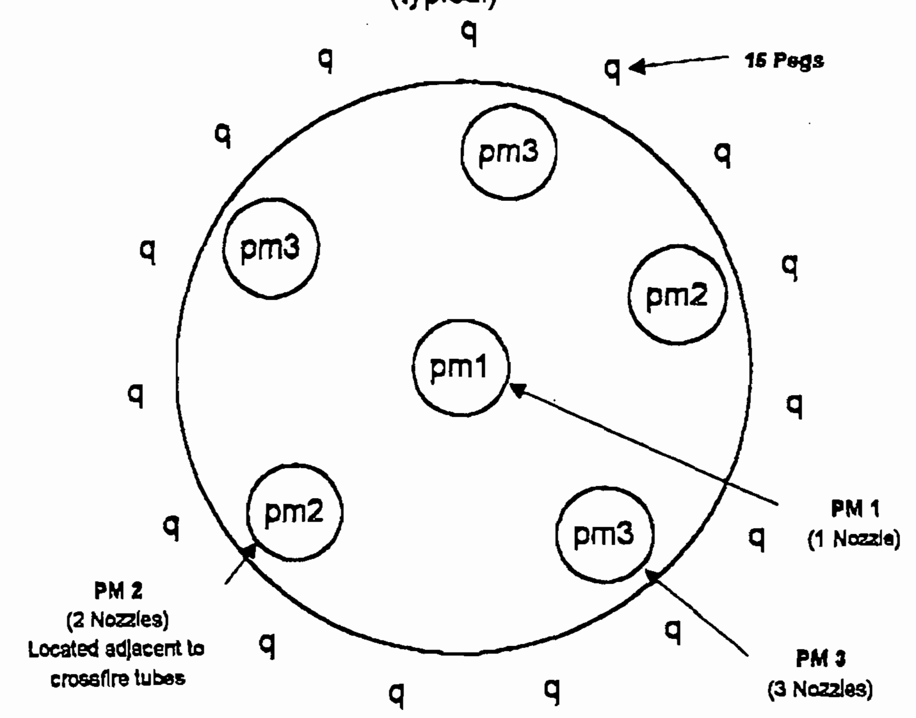
6.1.1.1 General

The dry low NOx 2.6 (DLN-2.6) conbustion system regulates the distribution of fuel delivered to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion chamber fuel nozzle assembly is calculated to maintain unit load and fuel split for optimal turbine emissions.

6.1.1.2 Gas Fuel System

The DLN 2.6 Combustion system consists of six fuel nozzles per combustion can, each operating as a fully premixed combustor, five located radially, one located in the center. The center nozzle, identified as PM1, (PreMix 1), two outer nozzles located adjacent to the crossfire tubes, identified as PM2, (PreMix 2), and the remaining three outer nozzles, identified as PM3, (PreMix 3). Another fuel passage, located in the airflow upstream of the premix nozzles, circumferentially around the combustion can, is identified as the quaternary fuel pegs, (see following illustration.)

DLN 2.6 Fuel Nozzle Arrangement
(typical)



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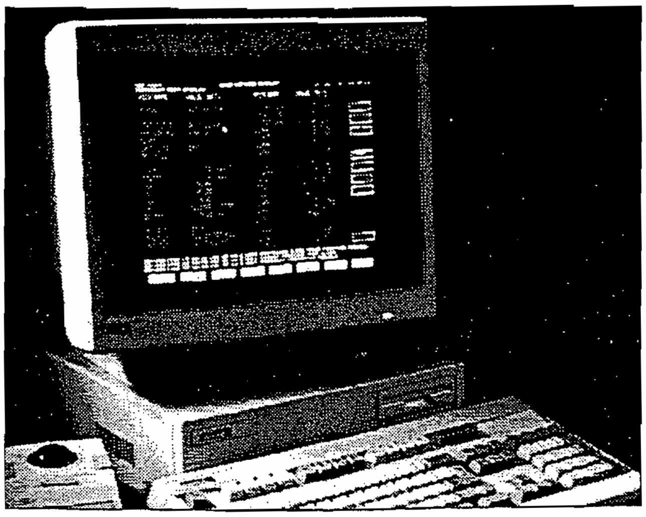

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Figure 10. Mark V operator interface

which ensures that no single hardware failure can interrupt communications between the gas turbine and the DCS system.

A specially configured PC is available to act as a "Historian," or <H> processor, for the gas turbine installation. All data available in the Mark V data base can be captured and stored by the historian. Analog data is stored when the values change beyond a settable deadband, and events and alarms are captured when they occur. In addition, data can be requested periodically or on demand in user definable lists. The historian is sized so that about a month's worth of data for a typical four unit plant can be stored on line, and provisions are included for both archiving and restoring older data. Display options include a full range of trending, cross-plotting and histogram screens.

Compliance with recognized standards is an important aspect of SPEEDTRONIC™ Mark V controls. It is designed to comply with several standards including the following:

ETL	–	Approval has been obtained for labeling of the Mark V control panel, with ETL labeling of complete control cabs.
CSA/UL	–	Approval has been obtained for the complete SPEEDTRONIC™ Mark V control panel.
UBC	–	Seismic Code Section 2312 Zone 4.
ANSI	–	B133.4 Gas Turbine Control and Protection System.
ANSI	–	C37.90A Surge Withstand.

HARDWARE CONFIGURATION

The SPEEDTRONIC™ Mark V gas turbine control system is specifically designed for GE gas and steam turbines, and uses a considerable number of CMOS and VLSI chips selected to minimize power dissipation and maximize functionality. The new design dissipates less power than previous generations for equivalent panels. Ambient air at the panel inlet vents should be between 0 and 40 C (32 and 72 F) with a humidity between 5 and 95%, non-condensing. The standard panel is a NEMA 1A panel that is 90 inches high, 54 inches wide, 20 inches deep, and weighs approximately 1200 pounds. Fig. 11 shows the panel with doors closed.

For gas turbines, the standard panel runs on 125 volt DC unit battery power, with AC auxiliary input at 120 volt, 50/60 Hz, used for the ignition transformer and the <I> processor. The

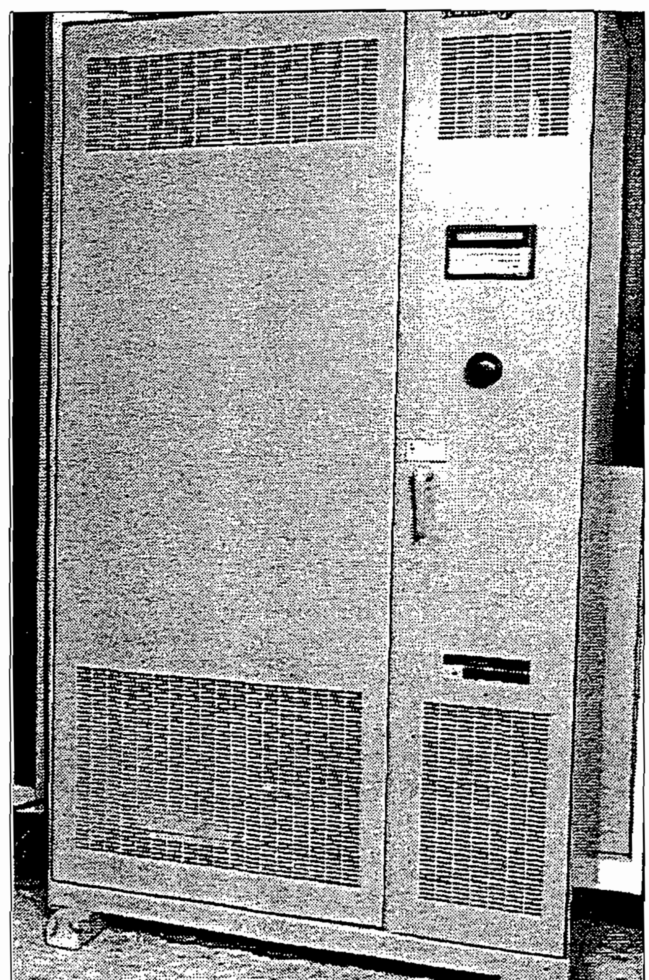

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Figure 11. Mark V turbine control panel

Transformers, a position sensor) produce a signal proportional to actuator position. Each control processor measures both LVDT signals and chooses the higher of the two signals. This value is chosen because the LVDT is designed to have a strong failure preference for low voltage output. The signal is compared with the position command and the error signal passed through a transfer function and a D/A converter to a current amplifier. The current amplifier from each control processor drives one of the three coils. The servo valve acts on the sum of the ampere turns. If one of the three channels fails, the maximum current that one failed amplifier can deliver is overridden by the combined signals from the remaining two good amplifiers. The result is that the turbine continues running under control.

The SIFT system ensures that the output fuel command signals to the digital servo stay in step. As a result, almost all single failures will not cause an appreciable bump in the controlled turbine parameter. Diagnostics of LVDT excitation voltage, LVDT outputs that disagree, and current not equalling the commanded value make it easy to find a system problem, so that on-line repair can be initiated quickly.

An independent protective module <P> is internally triple redundant. It accepts speed sensors, flame detectors, and potential transformer inputs to perform emergency electronic overspeed, flame detection, and synchronizing functions. Hardware voting for <P> solenoid outputs is accomplished on a trip card associated with the module. The trip card merges trip contact signals from the emergency overspeed, the main control processors, manual trip push buttons, and other hard-wired customer trips.

Overspeed and synchronization functions are independently performed in both the triple redundant control and triple redundant protective hardware, which reduces the probability of machine overspeed or out of phase synchronizing to the lowest achievable values.

SPEEDTRONIC™ Mark V control provides interfaces to DCS systems for plant control from the <I> processor. The two interfaces available are Modbus Slave Station and a standard Ethernet link, which complies with the IEEE-802.3 specification for the physical and medium access control (MAC) layers. A GE protocol is available for use over the Ethernet link. A hard-wired interface is also available.

Table 5 is a list of signals and commands available on the interfacing links. The table includes an option for hard-wired contacts and 4-20 ma signals intended to interface with older systems such as SCADA remote dispatch terminal units. The wires are connected to the I/O modules associated with <C>.

Table 5
INTERFACING OPTIONS

Hardwired
- Connects to Common "C" Processor I/O
- Commands to Turbine Control
  - Turbine Start/Stop
  - Turbine Fast Load
  - Governor Set Point Raise/Lower
  - Base/Peak Load Selection
  - Gas/Distillate Fuel Selection
  - Generator Voltage (VARS) Raise/Lower
  - Generator Synchronizing Inhibit/Release
- Feedback From Turbine Control:
  - Watts, VARS and Volts (Analog for Meters)
  - Breaker Status
  - Starting Sequence Status
  - Flame on Indication
  - On Temperature Control Indication
- Alarm Management:
  - RS232C Data Transmission Only, From <I>

Modbus Link
- Turbine Control Is Modbus Slave Station
- Transmission on Request by Master, 300 to 19,200 Baud
- Connects to Interface Processor (I)
- RS232C Link Layer
- Commands Available:
  - All Allowable Remote Commands Are Available
  - Alarm Management
- *Feedback From Turbine Control:*
  - Most Turbine Data Available in the I Data Base

The "stage link" that interconnects the <C> processor with the <I> processor is an extendable Arcnet link that allows daisy chaining multiple gas turbines with multiple <I> processors. Thus a single gas turbine can be controlled from multiple <I> processors, or a single <I> processor can control multiple gas and steam turbines. For multi-unit configurations, the <I> processor can be equipped with plant load control capability that will allow plant level management of all units for both real and reactive power. The <I> processor, or Operator Interface, is shown in Fig. 10.

In process plants where maintaining the link to the DCS is essential to keeping the plant online, two <I> processors are used to obtain redundant links to the DCS system. For critical installations, a redundant <C> processor option, referred to as the <D> processor, is available

Table 4
CRITICAL REDUNDANT SENSORS

PARAMETER	TYPE	FUNCTION	USAGE	NUMBER
SPEED	MAG. PICKUP	CTL & PROT	DEDICATED	3 TO 6
EXHAUST TEMP.	T.C.	CTL & PROT	DEDICATED	13 TO 27
GENERATOR OUTPUT	TRANSDUCER	CONTROL	DEDICATED	3
LIQUID FUEL FLOW	MAG. PICKUP	CONTROL	DEDICATED	3
GAS FUEL FLOW	TRANSDUCER	CONTROL	DEDICATED	3
WATER FLOW	MAG. PICKUP	CONTROL	DEDICATED	3
ACTUATOR STROKE	LVDT	CONTROL	SHARED	2/ACTUATOR
STEAM FLOW	TRANSDUCER	CONTROL	SHARED	1
VIBRATION	SEISMIC PROBE	PROTECTION	SHARED	8 TO 11
FLAME	SCANNER	PROTECTION	SHARED	4 TO 8
FIRE	SWITCH	PROTECTION	SHARED	17 TO 21
CONTROL OIL PRES.	SWITCH	PROTECTION	SHARED	3
L.O. PRES.	SWITCH	PROTECTION	SHARED	3
L.O. TEMP.	SWITCH	PROTECTION	SHARED	3
EXH. FRAME BLWR.	SWITCH	PROTECTION	SHARED	2
FILTER DELTA P.	SWITCH	PROTECTION	SHARED	3

NOTES:
1. DEDICATED SENSORS: ONE-THIRD ARE CONNECTED TO EACH PROCESSOR.
2. SHARED SENSORS ARE SHARED BY PROCESSORS.
3. THE NUMBER OF EXHAUST THERMOCOUPLES IS RELATED TO THE NUMBER OF COMBUSTORS.
4. VIBRATION AND FIRE DETECTORS ARE RELATED TO THE PHYSICAL ARRANGEMENT.
5. GENERATOR OUTPUT TRANSDUCERS ARE REDUNDANT ONLY FOR "CONSTANT SETTABLE DROOP" SYSTEMS.
6. DRY LOW NO_x HAS FOUR FLAME DETECTORS IN EACH OF TWO ZONES.

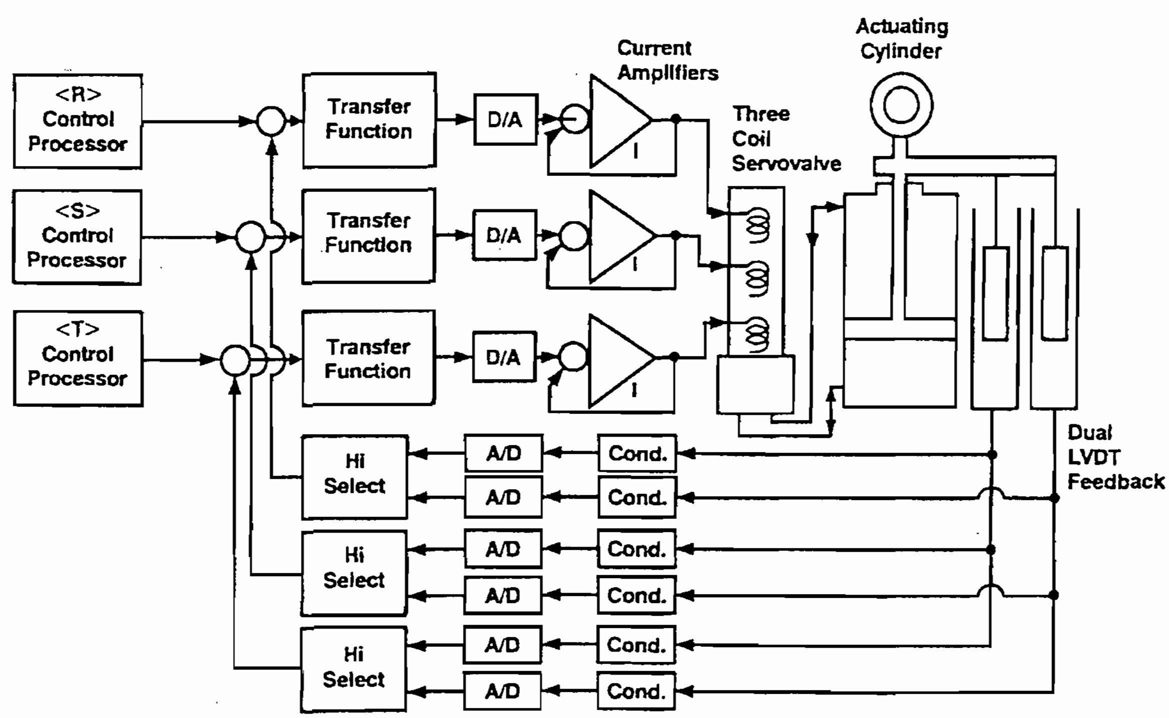

Figure 9. Digital servo position loops

SPEEDTRONIC™ MARK V CONTROL CONFIGURATION

The SPEEDTRONIC™ Mark V control system makes increased use of modern microprocessors and has an enhanced system configuration. It uses SIFT technology for the control, a new triple-redundant protective module, and a significant increase in hardware diagnostics. Standardized modular construction enhances quality, speed of installation, reliability, and ease of on-line maintenance. The operator interface has been improved with color graphic displays and standardized links to remote operator stations and distributed control systems (DCS).

Figure 8 shows the standard SPEEDTRONIC™ Mark V control system configuration. The top block in the diagram is the Interface Data Processor, called <I>. It includes a monitor, keyboard, and printer. Its main functions are driving operator displays, managing the alarm process, and handling operator commands. <I> also does system configuration and download, off-line diagnostics for maintenance, and implements interfaces to remote operator stations and plant distributed control systems.

The Common Data Processor, or <C>, collects data for display, maintains the alarm buffers, generates and keeps diagnostic data, and implements the common I/O for non-critical signals and control actions. Turbine supervisory sensors such as wheelspace thermocouples come directly to <C>. The <I> processor communicates with <C> using a peer-to-peer communication link which permits one or more <I> processors. <C> gathers data from the control processors by participating on the voting link.

At the core of SPEEDTRONIC™ Mark V control are the three identical control processors, called <R> <S> and <T>. All critical control algorithms, turbine sequencing, and primary protective functions are handled by these processors. They also gather data and generate most of the alarms.

The three control processors accept input from various arrangements of redundant turbine and generator sensors. Table 4 lists typical redundant sensor arrangements. By extending the fault tolerance to include sensors, as with the Mark IV system, the overall control system availability is significantly increased. Some sensors are brought in to all three control processors, but many, like exhaust thermocouples, are divided among the control processors. The individual exhaust temperature measurements are exchanged on the voter link so that each control processor knows all exhaust thermocouple values. Voted sensor values are computed by each of the control processors. These voted values are used in control and sequencing algorithms that produce the required control actions.

One key output goes to the servo valves used in position loops as shown in Fig. 9. These position loops are closed digitally. Redundant LVDT's (Linear Variable Differential

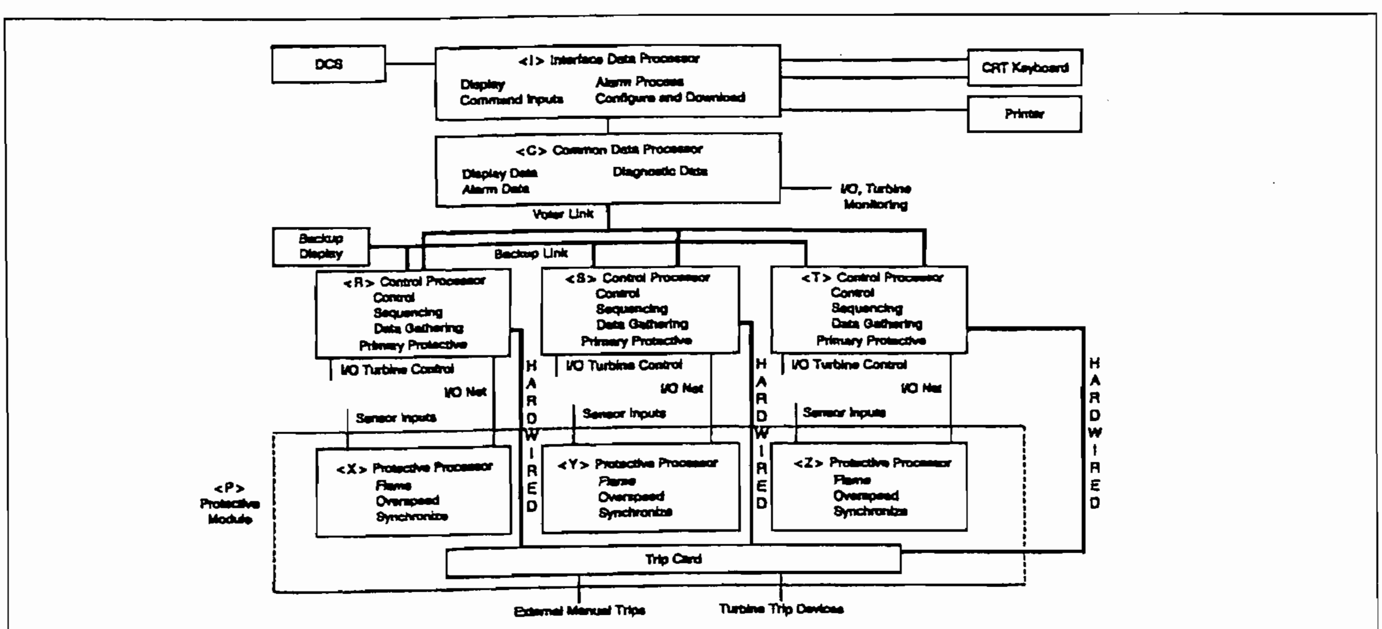

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Figure 8. Standard control configuration

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Gas turbines are capable of faster loading in the event of a system emergency. However, thermal fatigue duty for these fast load starts is substantially higher. Therefore, selection of a fast load start is by operator action, with the normal start being the default case.

Gas turbine generators that are equipped with diesel engine starting devices are optionally capable of starting in a blacked out condition, without outside electrical power. Lubricating oil for starting is supplied by the DC emergency pump, powered from the unit battery. This battery also provides power to the DC fuel forwarding pump for black starts on distillate. The turbine and generator control panels on all units are powered from the battery. An inverter supplies the AC power required for ignition and the local operator interface. Power for the cooling system fans is obtained from the main generator through the power potential transformer after the generator field is flashed from the battery at about 50% speed. The black start option utilizes a DC battery-powered turning device for rotor cool-down to ensure the integrity of the black start capability.

As mentioned previously, the protective function acts to trip the gas turbine independently from the fuel control in the event of overspeed, overtemperature, high rotor vibration, fire, loss of flame, or loss of lube oil pressure. With the advent of microprocessors, additional protective features have been added, with minimum impact on running reliability due to the redundancy of the microprocessors, sensors and signal processing. The added functions include combustion and thermocouple monitoring, high lube oil header temperature, low hydraulic supply pressure, multiple control computer faults, and compressor surge for the aircraft-derivative gas turbines.

Because of their nature or criticality, some protective functions trip the stop valve through the hard-wired, triple-redundant protective module. These functions are the hard-wired overspeed detection system, which replaces the mechanical overspeed bolt on some units, the manual emergency trip buttons, and "customer process" trips. As previously mentioned, the protection model performs the synchronization function to close the breaker at the proper instant. It also receives signals from the flame detectors and determines if flame is on or off. A block diagram of the turbine protective system is shown in Fig. 7. It shows how loss of lube oil, hydraulic supply, or manual hydraulic trip will result in direct hydraulic actuation of the stop valves.

Interfacing to other application-specific trip functions is provided through the three control processors, the hard-wired protection module, or the hydraulic trip system. These trip functions include turbine shutdown for generator protective purposes, and combined-cycle coordination with heat recovery steam generators and single-shaft STAG™ steam turbines. The latter is hydraulically integrated as shown in Fig. 7. Other protective coordination is provided as required to meet the needs of specific applications.

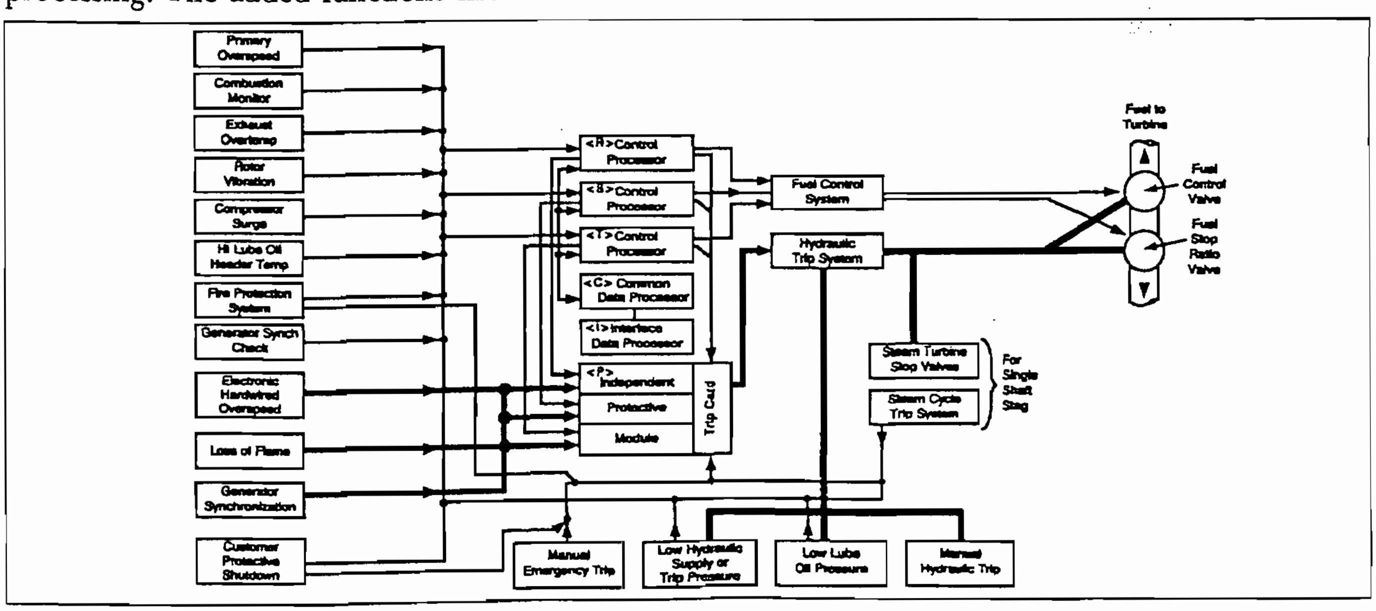

Figure 7. Protective system block diagram; SPEEDTRONIC™ Mark V turbine control

mined program of acceleration rates, slower initially, and faster just before reaching running speed. The purpose of this is to reduce the thermal fatigue duty associated with startup.

At about 40 to 85% speed, turbine efficiency has increased sufficiently so that the gas turbine becomes self sustaining, and external cranking power is no longer required. At about 80 to 90% speed, the compressor inlet guide vanes, which were closed during startup to prevent compressor surge, are opened to the full-speed, no-load position.

As the turbine approaches running speed, synchronizing is initiated. This is a two or three step process that consists of matching turbine generator speed, and sometimes voltage, to the bus, and then closing the breaker at the point where the two are in phase within predetermined limits.

Turbine speed is matched to the line frequency with a small positive differential to prevent the generator breaker from tripping on reverse power at breaker closure. In the protective module, triple redundant micro-processor-based synchronizing methods are used to predict zero phase angle difference and compensate for breaker closing time to provide true zero angle closure. Acceptable synchronizing conditions are independently verified by the triple redundant control processors as a check function.

At the completion of synchronizing, the turbine will be at a spinning reserve load. The final step in the starting sequence consists of automatic loading of the gas turbine generator, at either the normal or fast rate, to either a preselected intermediate load, base load, or peak load. Typical starting times to base load are shown in Table 3. Although the time to full speed no load applies to all simple cycle gas turbines, the loading rates shown are for standard combustion, and may vary for some dry low NO_x systems.

Normal shutdown is initiated by the operator, and is reversible until the breaker is opened and the turbine operating speed falls below 95%. The shutdown sequence begins with automatic unloading of the unit. The main generator breaker is opened by the reverse power relay at about five percent negative power, which drives the gas turbine fuel flow to a minimum value sufficient to maintain flame, but not turbine speed. The gas turbine then decelerates to about 40 to 25% speed, where fuel is completely shut off. As before, the purpose of this "fired shutdown" sequence is to reduce the thermal fatigue duty imposed on the hot gas path parts.

After fuel is shut off, the gas turbine coasts down to a point where the rotor turning system can be effective. The rotor should be turned periodically to prevent bowing from uneven cool-down, which would cause vibration on subsequent start-ups. Turning of the rotor for cool-down or maintenance is accomplished by a ratcheting mechanism on the smaller gas turbines, or by operation of a conventional turning gear on some larger gas turbines. Normal cool-down periods vary from five hours on the smaller turbines to as much as forty-eight hours on some of the larger units. Cool down sequences may be interrupted at any point for a restart if desired.

Table 3
SIMPLE CYCLE PACKAGE POWER PLANT STARTING TIMES

			Minutes				
Model Series	Type of Start	Starting Device	Diesel Warmup Time	+	Turbine Starting Time	=	Time to Full Speed No Load	Total Time to Base Load
LM6000	Normal	Hydraulic	NA		7.0		7.0	12.0
MS5001P	Normal	Diesel	2		7.17		9.17	13.17
	Fast Load	Diesel	1/2		7.17		7.67	9.67
	Emergency	Big Diesel	1/2		4.0		4.5	5.0
MS6001B	Normal	Diesel	2		10.0		12.0	16.0
	Fast Load	Diesel	1/2		6.67		7.17	9.17
MS7001EA	Normal	Motor	NA		7.5		7.5	19.5
	Fast Load	Motor	NA		7.5		7.5	9.0
MS7001FA	Normal	Motor/LCI	NA		9.0		9.0	21.0
MS9001E	Normal	Motor	NA		8.17		8.17	20.17
	Fast Load	Motor	NA		8.17		8.17	9.67
MS9001FA	Normal	Motor/LCI	NA		9.0		9.0	21.0

LCI = Load Commutating Inverter (Static Starter)

LIST OF FIGURES

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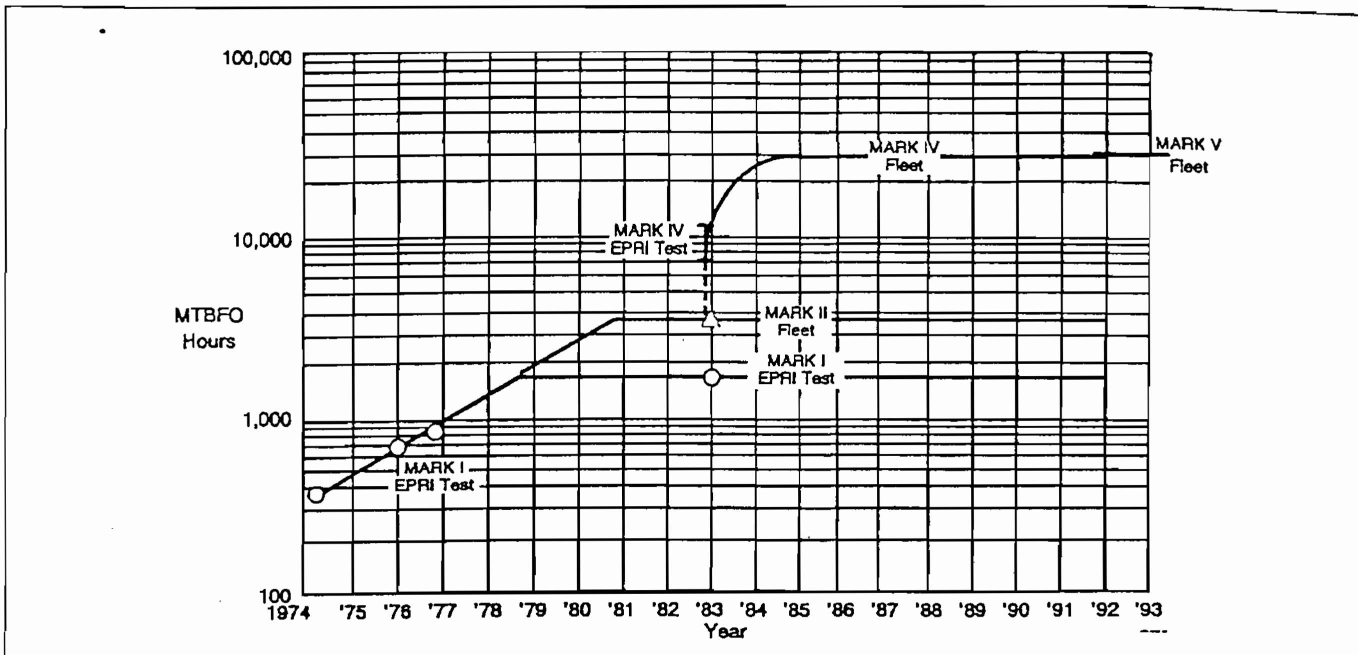

Figure 15. Control system reliability

components to fail, and fewer types of components in the control panel. (This also means that there are fewer spares to stock.) Two-out-of-three redundancy on critical functions and components ensures that failures, which are less likely to begin with, are also less likely to cause a turbine trip. Extensive built-in diagnostics and the ability to replace almost any component while running further minimize exposure time, while running with a failed component when the potential to trip resulting from a double failure, is highest. Finally, the high degree of standardized, yet still flexible, software and hardware allowed a much greater degree of automated manufacturing and testing, substantially lowering the potential for human error, and increasing the repeatability of the process.

The Mark V system is a further improvement over the Mark IV system. Although the two-out-of-three voting philosophy is retained, its implementation is improved and made more robust through use of Software Implemented Fault Tolerance techniques. Components, and types of components, have been further reduced in number. Standardization of hardware and software has been carried several steps further, but flexibility has also been increased. Greater degrees of automated manufacturing and testing have been complimented by greater utilization of computer-aided engineering to standardize the generation and testing of software and system configuration. Thus, it is fully expected the Mark V system will further advance the continuing growth of gas turbine control system starting and running reliability.

SUMMARY

The SPEEDTRONIC™ Mark V Gas Turbine Control System is based on a long history of successful gas turbine control experience, with a substantial portion using electronic and microprocessor techniques. Further advancements in the goals of starting and running reliability, and system availability will be achieved by logical evolution of the unique architectural features developed and initially put into service with the Mark IV system. Flexibility of application and ease of operation will also grow to meet the needs of generator and mechanical drive systems, in process and utility operating environments, and in both peaking and base load service.

REFERENCES

1. W.I. Rowen, "Operating Characteristics of Heavy Duty Gas Turbines in Utility Service," ASME Paper #88-GT-150, presented at the Gas Turbine and Aeroengine Congress, Amsterdam, The Netherlands – June 6-9, 1988.

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diagnostic routine. It is an indicator of degradation in the ultraviolet flame detection system.

In another example, the contact input circuits can be forced to either state and then be interrogated to ensure that the circuit functions correctly without disturbing their normal operation. The extent of this kind of diagnostics has been greatly increased in SPEEDTRONIC™ Mark V control over previous generations. This level of monitoring and diagnostics makes maintenance easier and faster so that the control system stays in better repair. A properly maintained panel is highly fault tolerant and makes systems starting and running reliability approach 100%.

Once the diagnostic routines have located a failed part, it may be replaced while the turbine continues to run. The most critical function of the diagnostics is to identify the proper control section where the problem exists. Wrong identification could lead to powering down a good section, resulting in a vote to trip. If the failed section is also voting to trip, the turbine will trip. A great deal of effort has been put into identifying the correct section. To effect the repair, the correct section is powered down. The module is opened and tilted out, the offending card located, cables disconnected, card replaced, and cables reconnected. The rack is closed and power is reapplied to the module. The module will then join in with the others to control the turbine, and the fault tolerance is restored.

Should the fault be in the <I> or <C> processor, it is likely that the operator display will stop or go blank, and that commands can no longer be sent by the operator to the turbine from <I>. This upsets the operator much more than it disturbs the control processors or turbine. A back-up display is provided to handle this situation. It happens very infrequently, and repair of the normal operator interface will usually be accomplished in less than three hours. Optional redundant <I> processors make the use of the back-up display even more unlikely. The gas turbine control is completely automatic and needs little human intervention for starting, running, stopping, or tripping once a sequence is initiated.

The back-up display provides for a minimum set of control commands: start, stop, raise load, and lower load. It reports all process alarms by number. Since the alarm text can be altered on site in <I>, a provision is included to print the alarms with their internal alarm numbers. This list is used to look up the alarm name from the alarm number. The same is true for data points; however, a preselected list of key data points are programmed into the back-up panel which display the short symbol name, value, and engineering units. The control ships from the factory with this limited list of key parameters established for the back-up display.

CONTROL SYSTEM EXPERIENCE

The SPEEDTRONIC™ Mark V Turbine Control System was initially put into service in May of 1992 on one of three industrial generator drive MS9001B gas turbines. The system was subsequently put into utility service on two peaking gas turbines to obtain experience in daily starting service in order to develop a starting reliability assessment in addition to the continuous duty running reliability assessment. General product line shipments of the Mark V System on new unit production commenced early in 1993, with new installations starting up throughout the second half of that year.

Today, virtually all turbine shipments include Mark V Turbine Controls. This includes 424 new gas turbines, and 106 new steam turbines either shipped or on order. In addition, almost eighty existing units have been committed to retrofitted SPEEDTRONIC™ Mark V Turbine Control Systems, however, the bulk of these are designed as Simplex rather than the triple redundant systems associated with new units. This is due to the floor space available in retrofit applications. Reliability of the in service fleet, subsequent to commissioning and after accumulating over 1.4 million powered operational hours on 264 units, has been as expected. Indicated MTBFO (Mean-Time-Between-Forced-Outages) is in excess of 28,000 hours for the system, which includes control panel, sensors, actuators, and all intervening wiring and connectors. This performance is shown relative to the rest of the electronic control history in Figure 15.

Why is the Mark V system so much better than its predecessors? First of all, there are fewer

Displays for normal operation center around the unit control display. It shows the status of major selections and presents key turbine parameters in a table that includes the variable name, value, and engineering units. A list of the oldest three unacknowledged alarms appears on this screen. The operator interface also supports an operator-entered list of variables, called a user defined display, where the operator can type in any turbine-generator variable, and it will be added to the variable list. Commands that change the state of the turbine require an arm activate sequence to avoid accidental operation. The exception is setpoint incrementing commands, which are processed immediately and do not require an arm-activate sequence.

Alarm management screens list all the alarms in the chronological order of their time tags. The most recent alarm is added to the top of the display list. The line shows whether the alarm has been acknowledged or not, and whether the alarm is still active. When the alarm condition clears, the alarm can be reset. If reset is selected and the alarm has not cleared, the alarm does not clear and the original time tag is retained.

The alarm log prints alarms in their arrival sequence, showing the time tags which are sent from the control modules with each alarm. Software is provided to allow printing of other information, such as copying of text screens, or making a listing of the full text of all alarms or turbine variables. When the printer has been requested to make such an output, it will form feed, print the complete list, and form feed again. Any alarms that happened during the time of printing were stored and are now printed. An optional alternative is to add a second printer, dedicating one to the alarm log.

Administrative displays help with various tasks such as setting processor real time clocks and the date. These displays will include the selection of engineering units and allow changing between English and metric units.

There are a number of diagnostic displays that provide information on the turbine and on the condition of the control system. A partial list of the diagnostics available is presented in Table 7. The trip diagnostic screen traps the actual signal condition that caused a turbine trip. This display gives detailed information about the actual logic signal path that caused any trip. It is accomplished by freezing information about the logic path when the trip occurs. This is particularly useful in identifying the original source of trouble if a spurious signal manages to cause one of the control processors to call for a trip and does not leave a normal diagnostic trail. In SPEEDTRONIC™ Mark V controls, all trips are annunciated, and information about the actual logic path that caused the trip is captured. In addition to this information, contact inputs are resolved to one millisecond, which makes this sequence of events information more valuable.

Table 7
MONITORING AND DIAGNOSTICS

- Power
  - Incoming Power Sources
  - Power Distribution
  - All Control Voltages
  - Battery Ground, Non-Interfering With Other Ground Detectors
- Sensors and Actuators -
  - Contact Inputs Circuits; Can Force and Interrogate
  - Open Thermocouple
  - Open and Short on Seismic Vibration Transducers
  - LVDT Excitation Voltage
  - Servovalve Current Feedback Loopback Test
  - 4/20 MA Control Outputs - Loopback Testing
  - Relay Driver; Voting Current Monitor
  - RTD Open and Short
- Protective
  - Flame Detector; UV Light Level Count Output
  - Synchronizer - Phase Angle at Closure
  - Trip Contact Status Monitor
- Voted Data -
  - Voting Mismatch

The previously mentioned comparison of voting values is another powerful diagnostic tool. Normally these values will agree, and significant disagreement means that something is wrong. Diagnostic alarms are generated whenever there is such a disagreement. Examination of these records can reveal what has gone wrong with the system. Many of these combinations have specific diagnostics associated with them, and the software has many algorithms that infer what has gone wrong from a pattern of incoming diagnostic signals. In this way the diagnostic alarm will identify as nearly as possible what is wrong, such as a failed power supply, blown fuse, failed card, or open sensor circuit.

Some of the diagnostics are intended to enhance turbine-generator monitoring. For instance, reading and saving the actual closing time of the breaker is an excellent diagnostic on the health of the synchronizing system. An output from the flame detectors which shows the effective ultraviolet light level is another new tective function in the control processors, each activate a relay driver. The driver signals are sent to the trip card in the protective model where independent relays are actuated. Contacts from each of these three primary protective trip relays are voted to cause the trip solenoid to drop out. Separate overspeed pickups are brought to the independent protective module. Their relay contacts are wired in a voting arrangement to the other side of the trip solenoid, and independently cause the trip solenoid to drop out on detection of overspeed.

The <I> processor is equipped with a hard disk which keeps the records that define the site software configuration. It comes from GE with the site-specific software properly configured. For most upgrades, the basic software configuration on the disk is replaced with new software from the GE factory. The software is quite flexible, and most required alterations can be made on site by qualified personnel. Security codes limit access to the programs used to change constants and sequencing, do logic forcing, manual control, and so forth. These codes are under the control of the owner, so that if there is a need to change access codes, new ones can be established on site. Basic changes in configuration, such as an upgrade to turbine capability, requires that the new software be compiled in <I> and downloaded to the processor modules. The information for <C> is stored in EEPROM there. The information for the control processors is passed through <C> and stored in EEPROM in <R> <S> and <T>. Once the download is complete, the <I> processor can fail and the turbine will continue to run properly, accepting commands from the local backup display, while <I> is being repaired.

Changes in control constants can be accomplished on-line in working memory. For example, a new set of tuning constants can be tried. If they are found to be satisfactory, they can be uploaded for storage in <I>, where they will be retained for use in any subsequent software download. <I> also keeps a complete list of variables, which can be displayed and printed.

The most critical algorithms for protective, control, and sequencing have evolved over many years of GE gas turbine experience. These basic algorithms are in EPROM. They are tuned and adapted with constants that are field adjustable. By protecting these critical algorithms from inadvertent change, the performance and safety of the complete fleet of GE gas turbines is made more secure.

OPERATION AND MAINTENANCE

The operator interface is comprised of a VGA color graphics monitor, keyboard, and printer. The functions available on the operator interface are shown in Table 6.

Table 6
OPERATOR INTERFACE FUNCTIONS

- Control
  - –Unit Control
  - –Generator Control (or Load Control)
  - –Alarm Management
  - –Manual Control (Examples)
    - •Preselected Load Setpoint
    - • Inlet Guide Vane Control
    - •Isochronous Control
    - •Fuel Stroke Reference
    - •Auxiliary Control
    - •Water Wash
    - •Mechanical Overspeed Test
- Data (Examples)
  - –Exhaust Temperatures
  - –Lube Oil Temperatures
  - –Wheelspace Temperatures
  - –Generator Temperatures
  - –Vibration
  - –Timers and Event Counters
  - –Emission Control Data
  - –Logical Status
    - •Contracts In
    - •Relay Out
    - •Internal Logic
  - –Demand Display
    - •Periodic Logging
- Administrative–
  - –Set Time/Date
  - –Select Scale Units
  - –Display Identification Numbers
  - –Change Security Code
    - •Maintenance/Diagnostics
  - –Control Reference
  - –Configuration Tools
  - –Tuning Tools
    - •Constant Change Routines
  - –Actuator Auto-Calibrate
  - –Trip Display
  - –Rung Display
  - –Logic Forcing
  - –Diagnostic Alarms
  - –Diagnostic Displays
    - •Off Line
    - •On Line
  - –System Memory Access

SOFTWARE CONFIGURATION

Improved methods of implementing the triple modular redundant system center on SIFT (Software Implemented Fault Tolerance) technology and result in a more robust control. SIFT involves exchanging information on the voter link directly between <R> <S> <T> and <C> controllers. Each control processor measures all of its input sensors so that each sensor signal is represented by a number in the controller. The sensor numbers to be voted are gathered in a table of values. The values of all state outputs such as integrators, for example the load setpoint, are added to the table. Each control processor sends it's table out on the voter link and receives tables from the other processors. Consider the <R> controller: it outputs its table to, and receives the tables from, the <S> and <T> controllers. Now all three controller tables will be in the <R> processor which selects the median value for each sensor and integrator output, and uses these voted outputs in all subsequent calculations. <S> and <T> follow the same procedure.

The basic SIFT concept, then, brings one sensor of each kind into each of <R> and <S> and <T>. If a sensor fails, the controller with the failed transducer initially has a bad value. But it exchanges data with the other processors, and when the voting takes place, the bad value is rejected. Therefore, a SIFT based system can tolerate one failed transducer of each kind. In previous systems, one failed transducer was likely to cause one processor to vote to trip. A failure of a different kind of transducer on another controller could cause a turbine trip. This does not happen with SIFT because the input data is exchanged and voted.

<C> is also connected to the voter link. It eavesdrops while all three sets of variables are transmitted by the control processors and calculates the voted values for itself. If there are any significant disagreements, <C> reports them to <I> for operator attention and maintenance action. If one of the transducers has failed, its output will not be correct and there will be a disagreement with the two correct values. <C> will then diagnose that the transducer, or parts immediately associated with it, have failed and will post an alarm to <I>.

Voting is also performed on the outputs of all integrators and other state variables. By exchanging these variables, fewer bumps in output are caused when a failure or a repair takes place. For instance, if a turbine is set to run on isochronous speed control with an isolated load, there is an integrator that compares the frequency of the generator with the nominal frequency reference (50 or 60 Hz). Any error is integrated to produce the fuel command signal. If one computer calculates an erroneously high fuel command, nothing happens because the processors will exchange the fuel command and vote, and all will use the correct value of fuel command. When the processor is repaired and put back in service, its fuel command will initially be set to zero. But as soon as the first data is exchanged on the voter link, the repaired control processor will output the voted value which will be from one of the running processors, so no bump in fuel flow will occur. No special hardware or software is needed to keep integrated outputs in step.

Since there is only one turbine connected to each panel, the triple-redundant control information must be recombined. This recombination is done in software or, for more critical signals, in dedicated voting hardware. For critical outputs, such as the fuel command, the recombination of the signals is done by the servo valve on the turbine itself as previously explained.

For example, up to four critical 4 to 20 ma outputs are voted in a dedicated electronic circuit. The circuit selects the median signal for output. It takes control power for the electronics and the actual output current from all three sections such that any two control sections will sustain the correct output. Non-critical outputs are software voted and output by the I/O associated with <C>.

Logic outputs are voted by dedicated hardware relay driver circuits that require two or three "on" signals to pick up the output relay. Control power for the circuit and output relay is taken from all three control sections.

Protective functions are accomplished by the control processors and, for overspeed, independently by the Protective Module <P> as well. Primary speed pickups are wired to the control processors and used for both speed control and primary overspeed protection. The trip commands, generated by the primary overspeed protypical standard panel will require 900 watts of DC and 300 watts of auxiliary ac power. Alternatively, the auxiliary power can be 240 volt AC 50 Hz, or it can be supplied from an optional black start inverter from the battery.

The power distribution module conditions the power and distributes it to the individual power supplies for the redundant processors through replaceable fuses. Each control module supplies its own regulated DC busses via DC/DC converters. These can accept an extremely wide range of incoming DC, which makes the control tolerant of significant battery voltage dips, such as those caused by starting a diesel cranking motor. All power sources and regulated busses are monitored. Individual power supplies can be replaced while the turbine is running.

The Interface Data Processor, particularly a remote <I>, can be powered by house power. This will normally be the case when the central control room has an Uninterruptible Power Supply (UPS) system. AC for the local <I> processor will normally be supplied via a cable from the SPEEDTRONIC™ Mark V panel or alternatively from house power.

The panel is constructed in a modular fashion and is quite standardized. A picture of the panel interior is shown in Fig. 12, and the modules are identified by location in Fig. 13. Each of these modules is also standardized, and a typical processor module is shown in Fig. 14. They feature card racks that tilt out so cards can be individually accessed. Cards are connected by front-mounted ribbon cables which can be easily disconnected for service purposes. Tilting the card rack back in place and closing the front cover locks the cards in place.

Considerable thought has been given to the routing of incoming wires to minimize noise and crosstalk. The wiring has been made more accessible for ease of installation. Each wire is easily identified and the resulting installation is neat.

The panels are made in a highly standardized manufacturing process. Quality control is an integral part of the manufacturing; only thoroughly tested panels leave the factory. By having a highly controlled process, the resulting modules and panels are very consistent and repeatable.

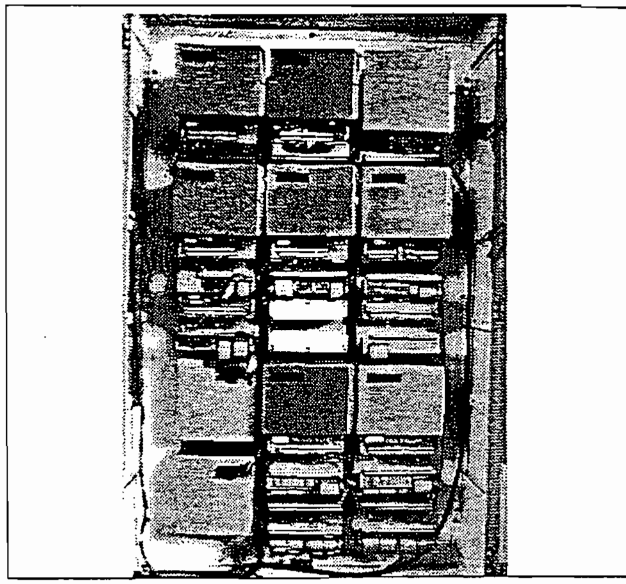

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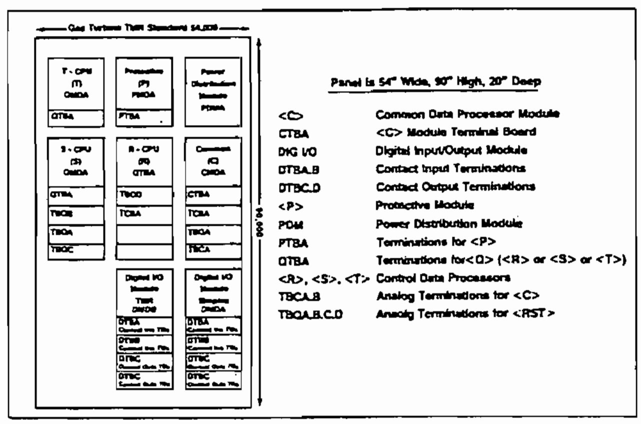
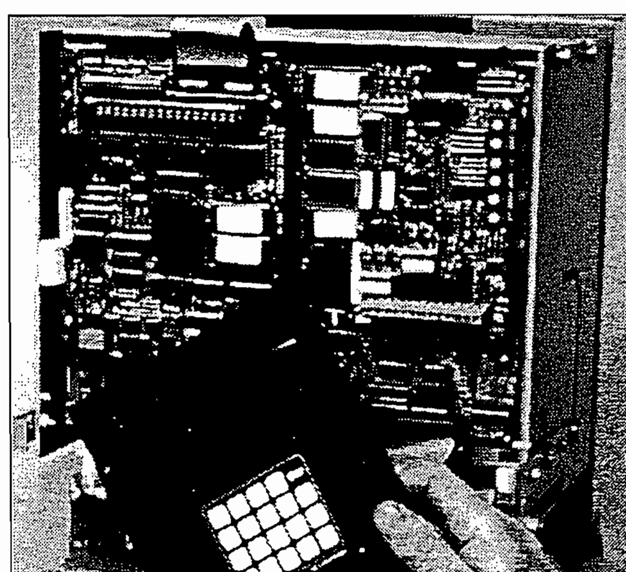
Figure 12. Panel internal arrangement



GT20783A

Figure 13. Module map of panel interior



GT21533A

Figure 14. Typical processor module

Exhibit D

Combustion Turbine

Start-Up / Shut-Down

Data

06/19/98 GRS

Combined Cycle Startup Curves

Notes

I) The units for accumulated heat consumption used in these curves are %-hr. A value of 100 %-hr is the heat consumption of the unit at base load ISO ambient for one hour. To convert the value from a curve in %-hr to engineering units multiply the curve value of %-hr by the quantity, base heat consumption for the unit in engineering units divided by 100%.

Ex/ Accumulated heat consumption to complete the start is 28 %-hr as read from the curve. If base heat consumption is 545.2 M Kcal/hr LHV, then the estimated startup heat consumption is,

$$28\ \%\text{-hr} \times \frac{545.2\ \text{M Kcal}}{\text{hr} \times 100\ \%} = 152.7\ \text{M Kcal}$$

or 28% of heat consumption at base for an hour.

II) The starts are defined by the amount of time the unit has been shutdown, following the normal (hot) shutdown procedure, prior to the startup.

Hot start = 8 hours prior shutdown
Warm start = 48 hours prior shutdown
Cold start = 72 hours prior shutdown

III) The definition of start used here is from unit rolloff of turning gear to the time the GT (or GTs) get to base load with the ST in Inlet Pressure Control IPC meaning the steam bypasses are shut and the plant is operating in a Combined Cycle mode. Not included in this interval is the continued increase in ST output due to the steam cycle lag, primarily characterized by the HRSG time constant, following the time when GT(s) reach base. The time at which the ST actually reaches base load is not practical to determine for test purposes due to the gradually increasing load characteristic of the ST after the GT(s) reach base

IV) Assumed prestart conditions include ST sealing steam is on and condenser vacuum established. If a source of sealing steam is not available prior to startup, for example from an auxiliary boiler, a previously running unit, a nearby steam source, etc., then the starting time will be increased by the time required to establish ST seals and pull vacuum, typically 30 minutes.

V) The curves were created based on ISO conditions. Certain parameters such as the GT load used for initial steam temperature setting will vary somewhat for non-ISO ambient conditions. For example, the GT load used for hot start is 20% based on ISO ambient temperature. At 0 deg F ambient it would be 10% and 120 deg F ambient would give 28%.

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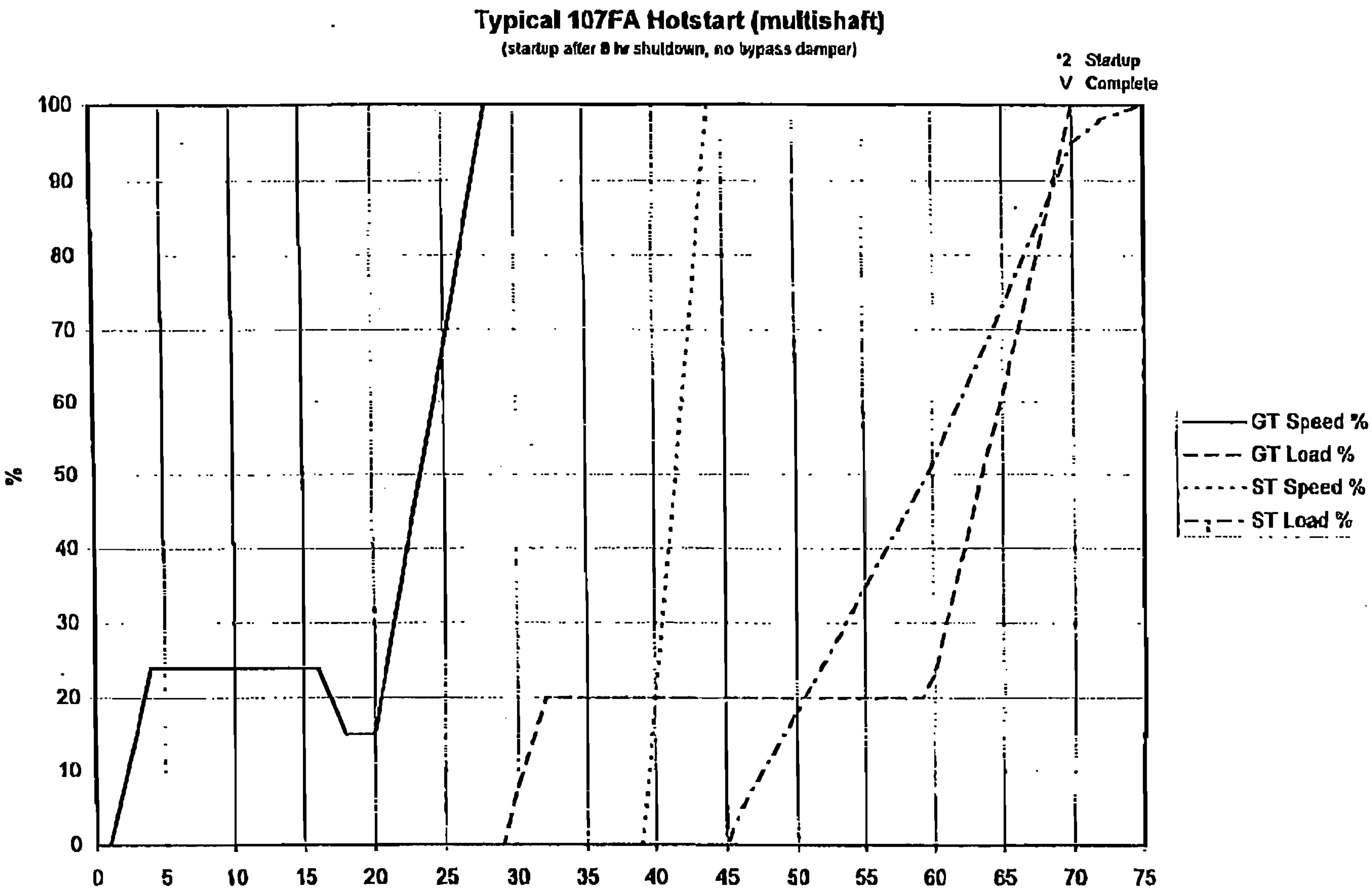

*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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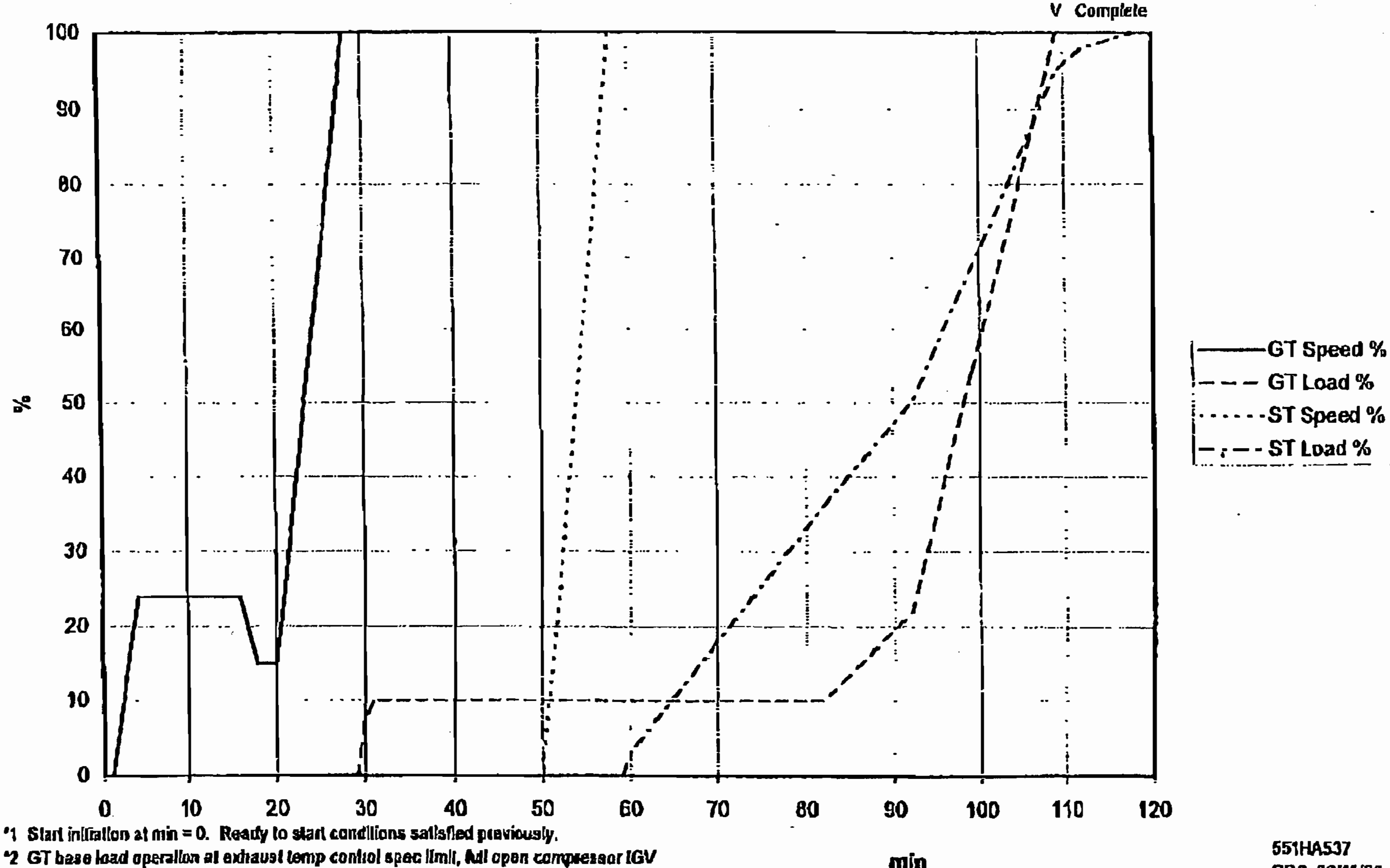
Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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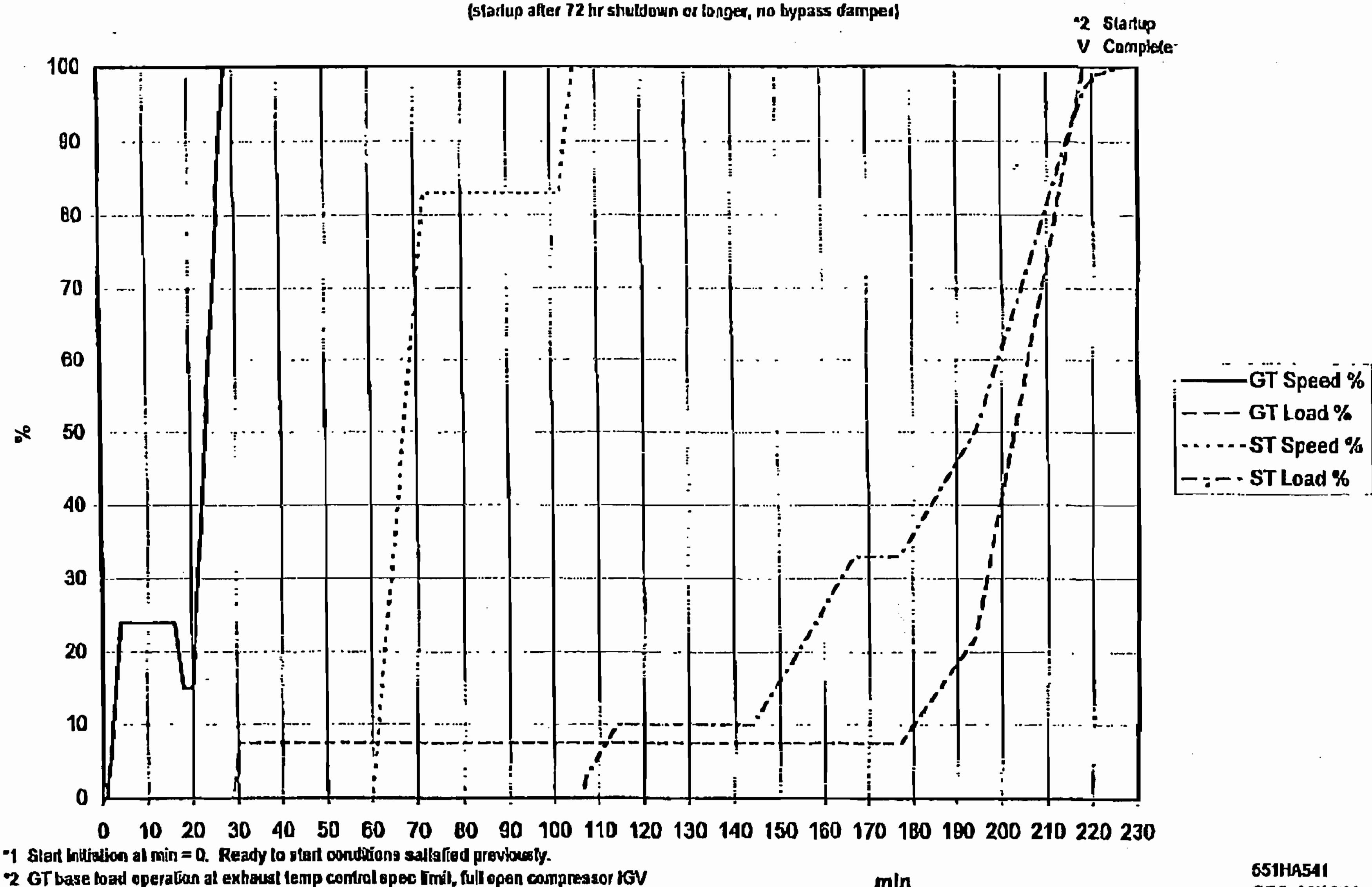
Best Available Copy

Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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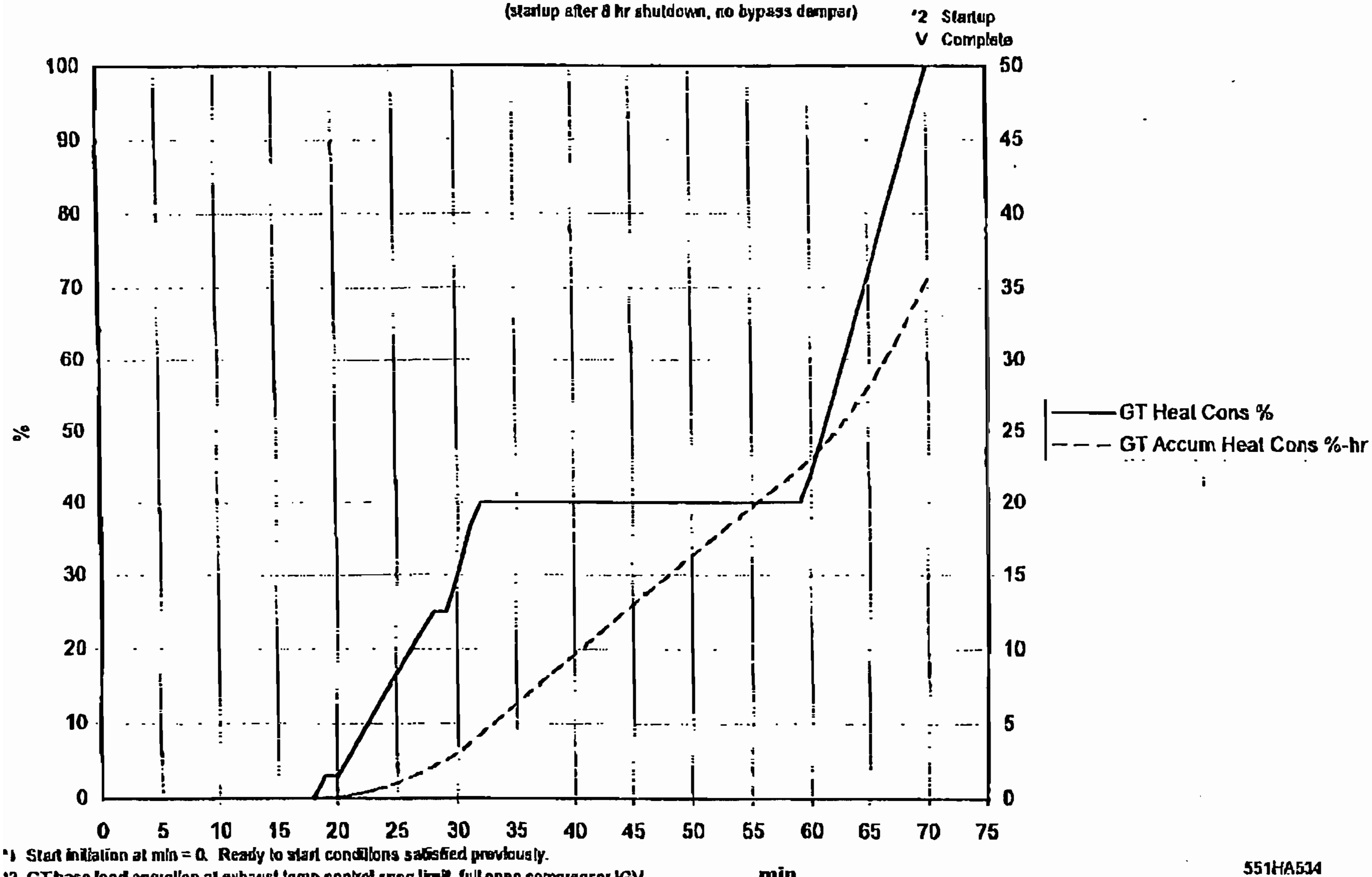
Typical 107FA Hotstart (multishaft)

(startup after 8 hr shutdown, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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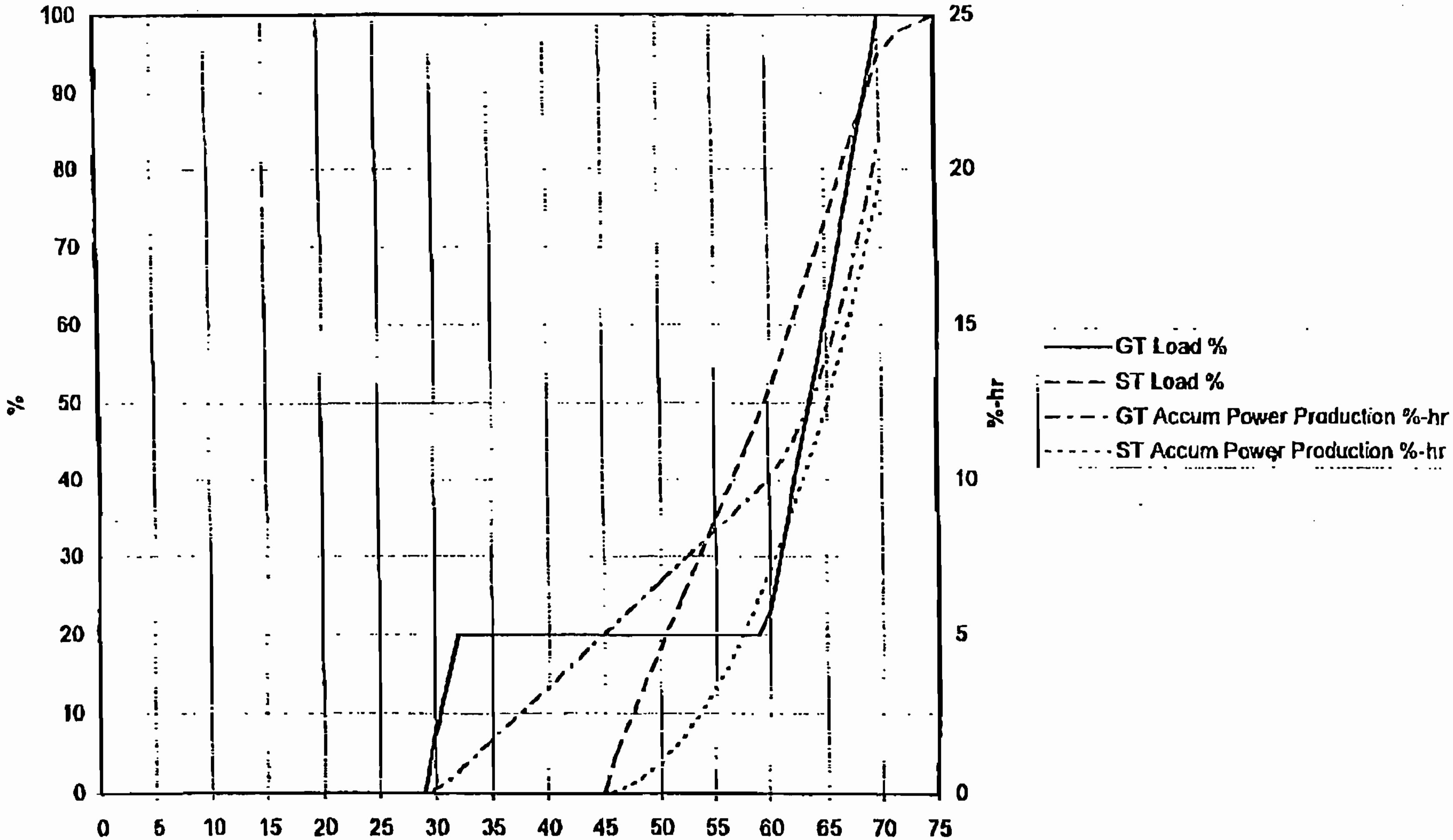
Typical 107FA Hotstart (multishaft)

(startup after 8 hr shutdown, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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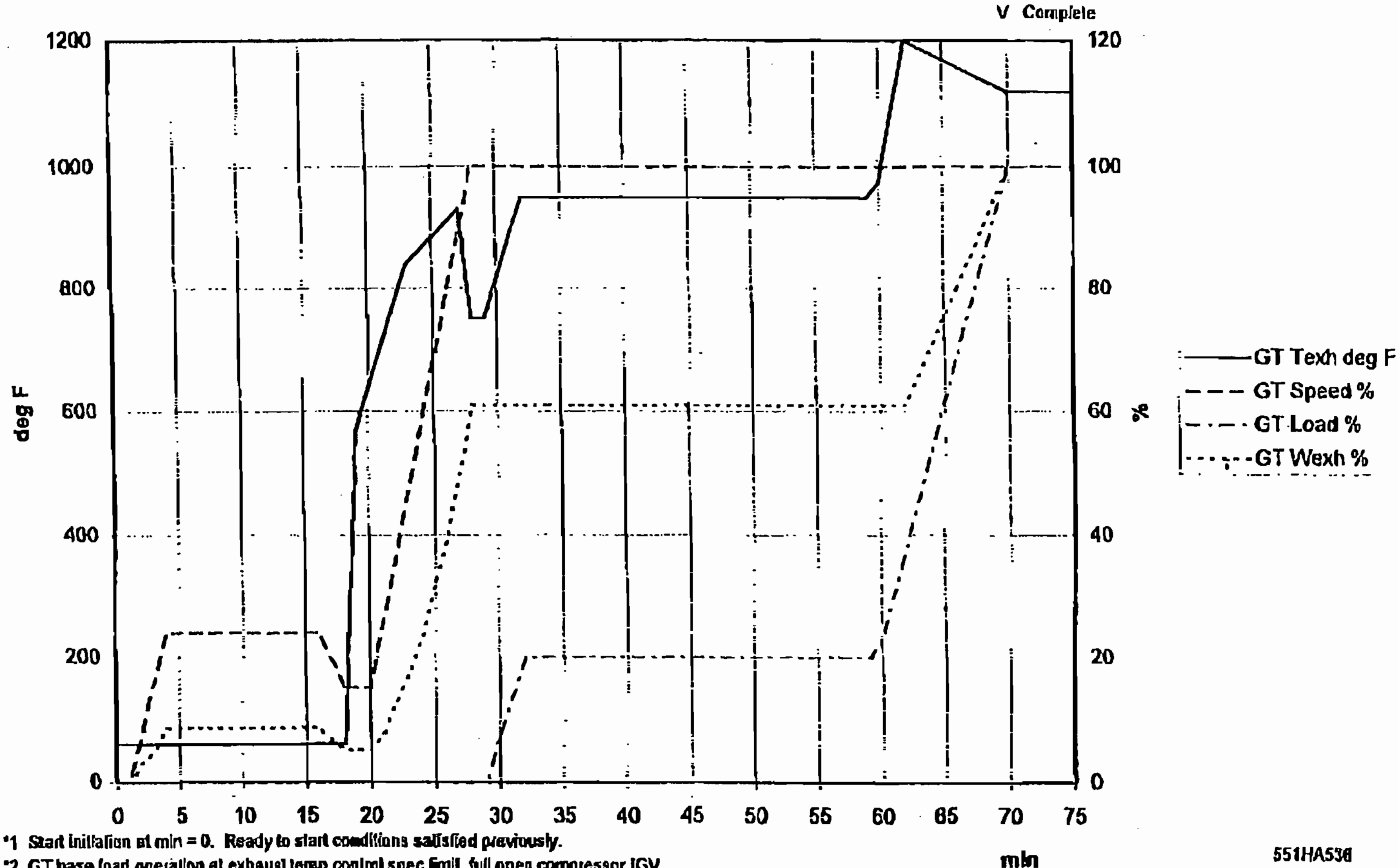
Typical 107FA Hotstart (multistart)

(startup after 8 hr shutdown, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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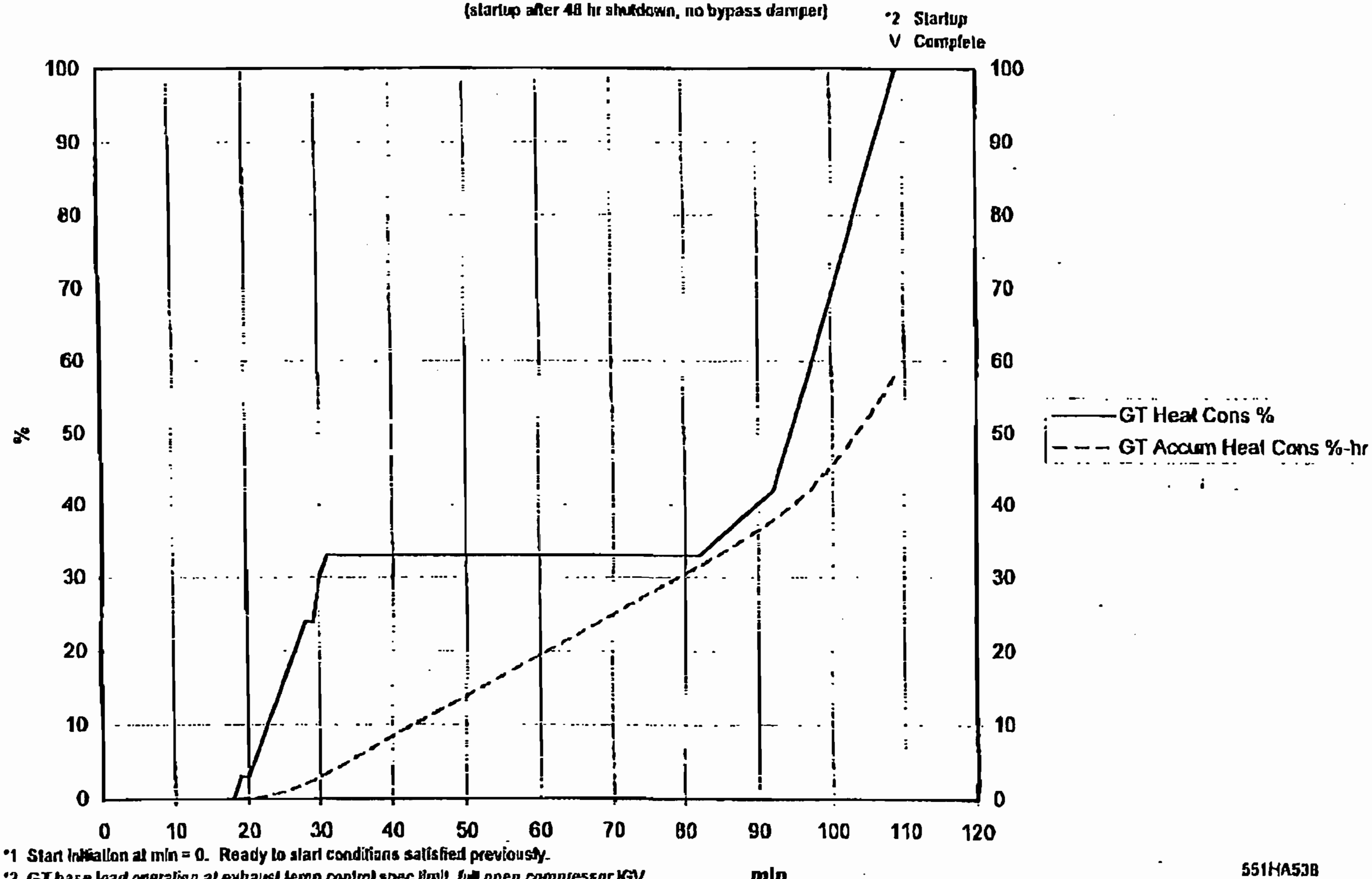
Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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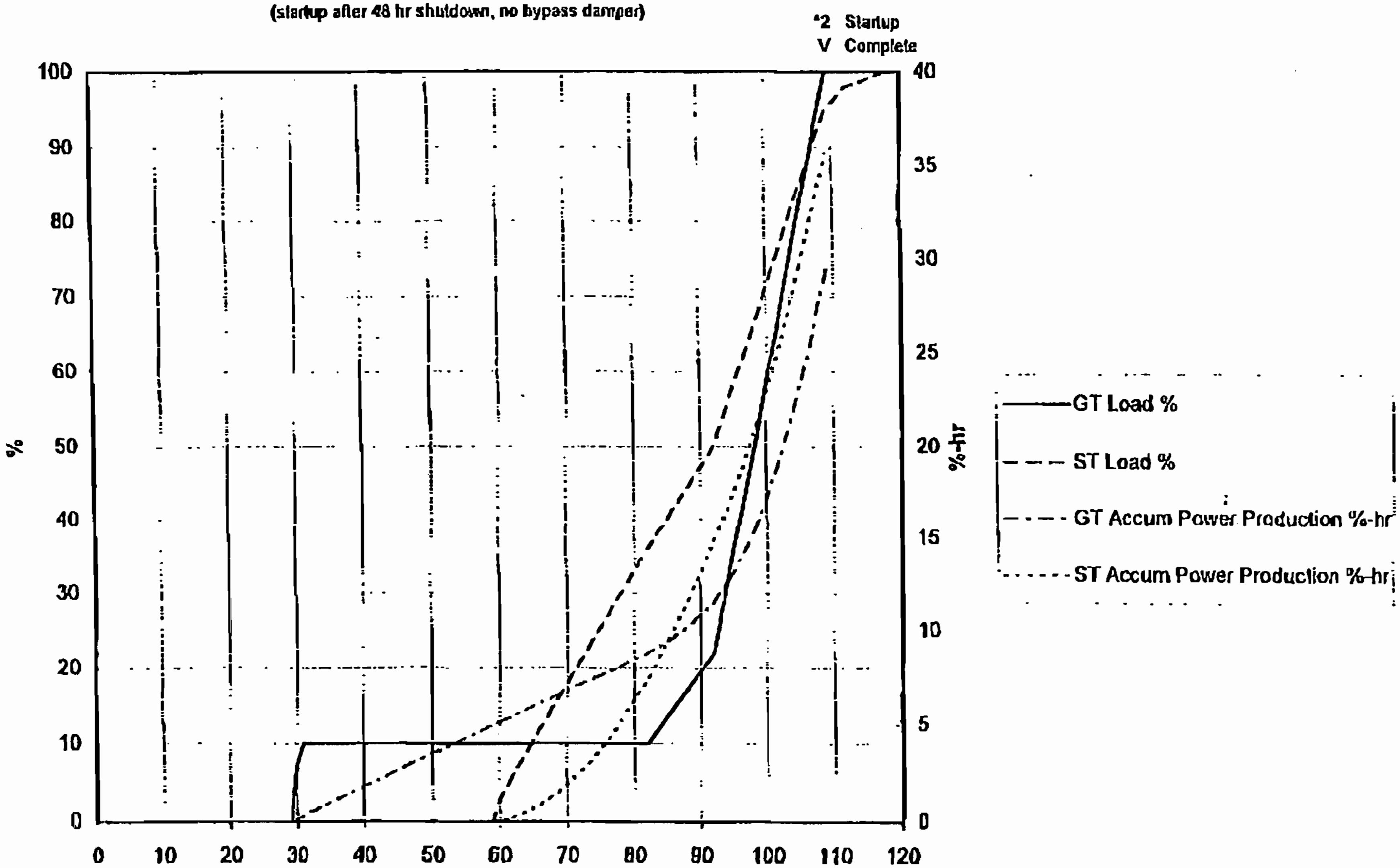
Best Available Copy

Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)



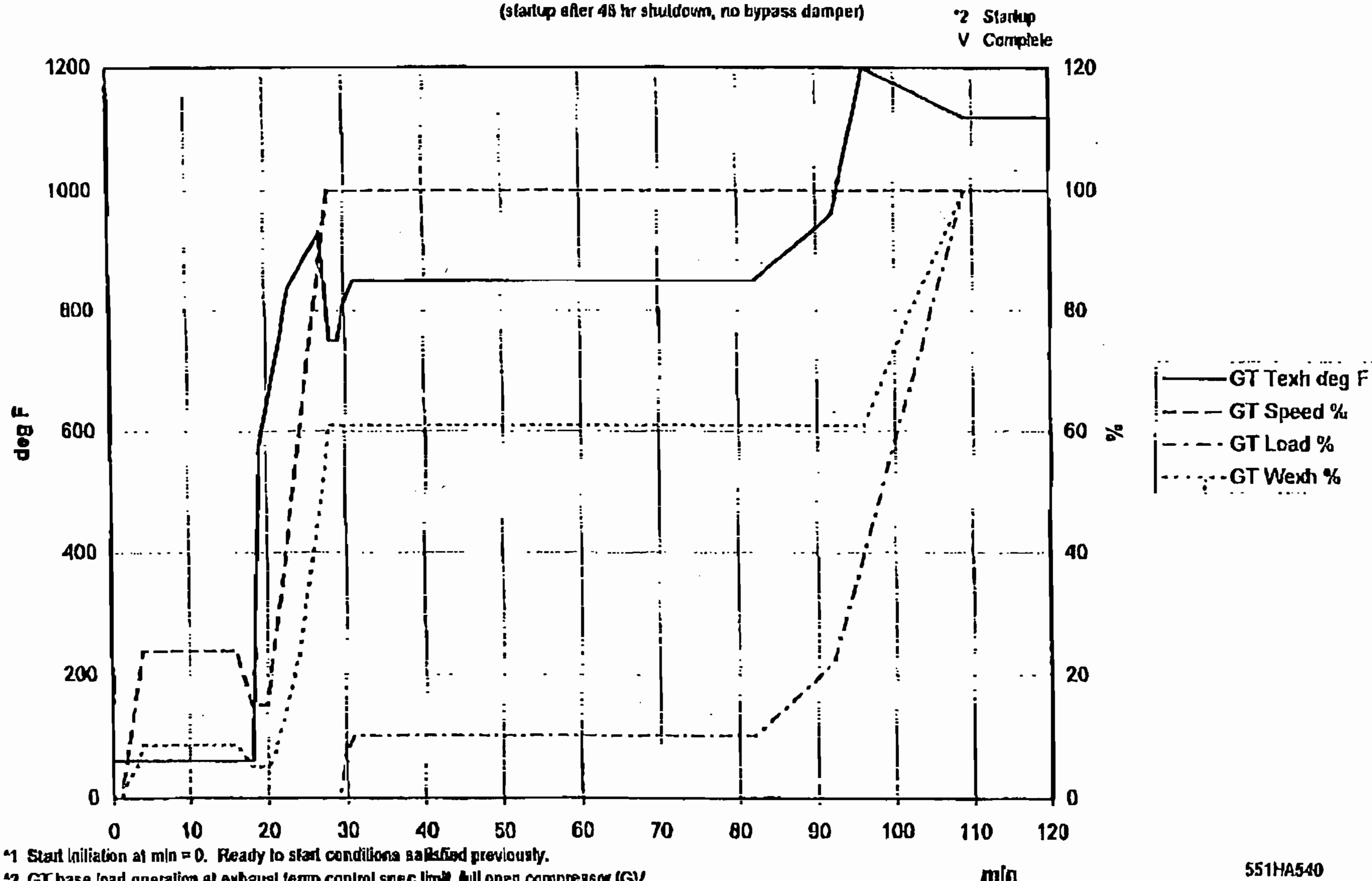
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA539
GRS 06/15/98

Best Available Copy

Typical 107FA Warmstart (multishaft)

(startup after 48 hr shutdown, no bypass damper)



*1 Start initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

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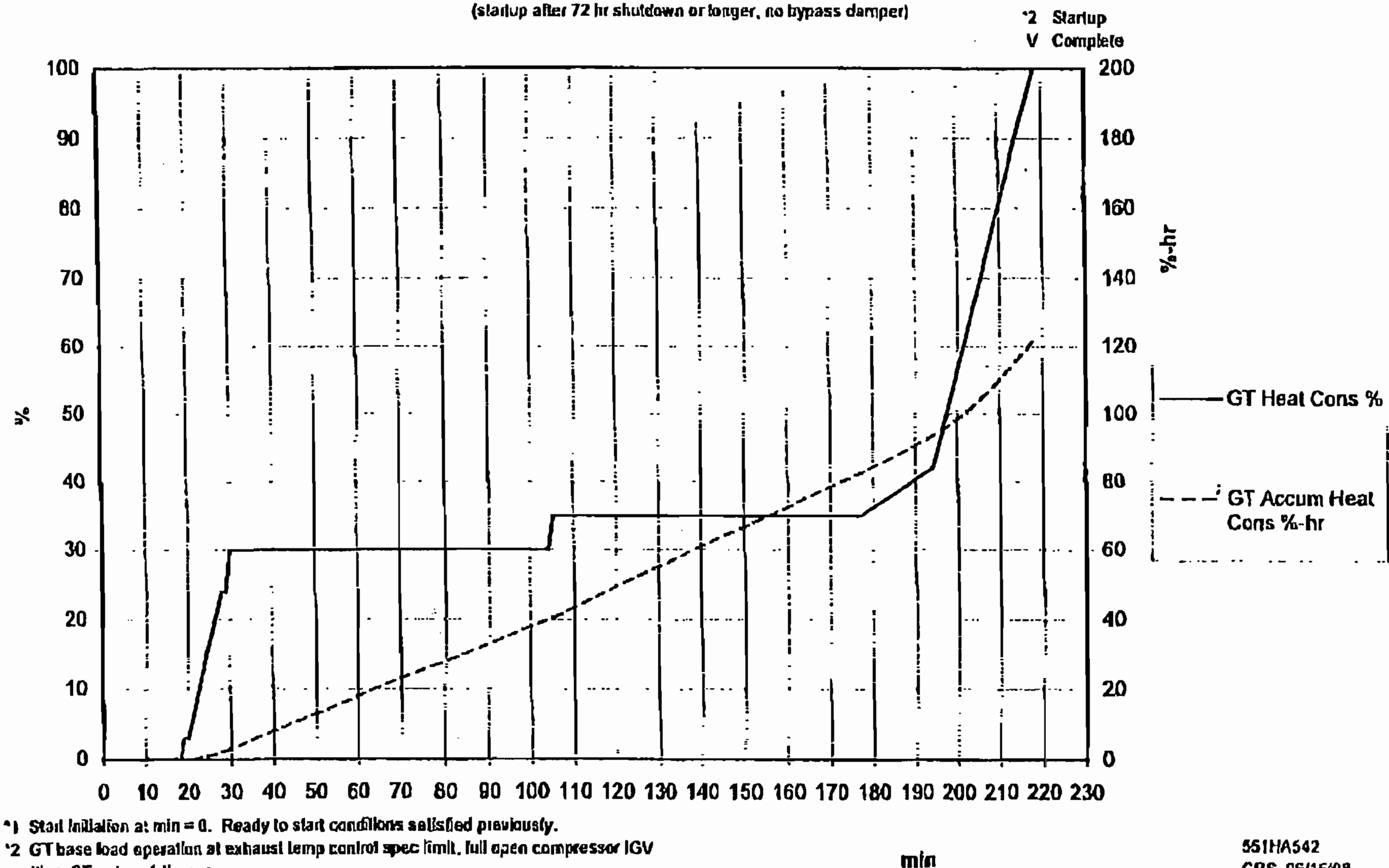
Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)



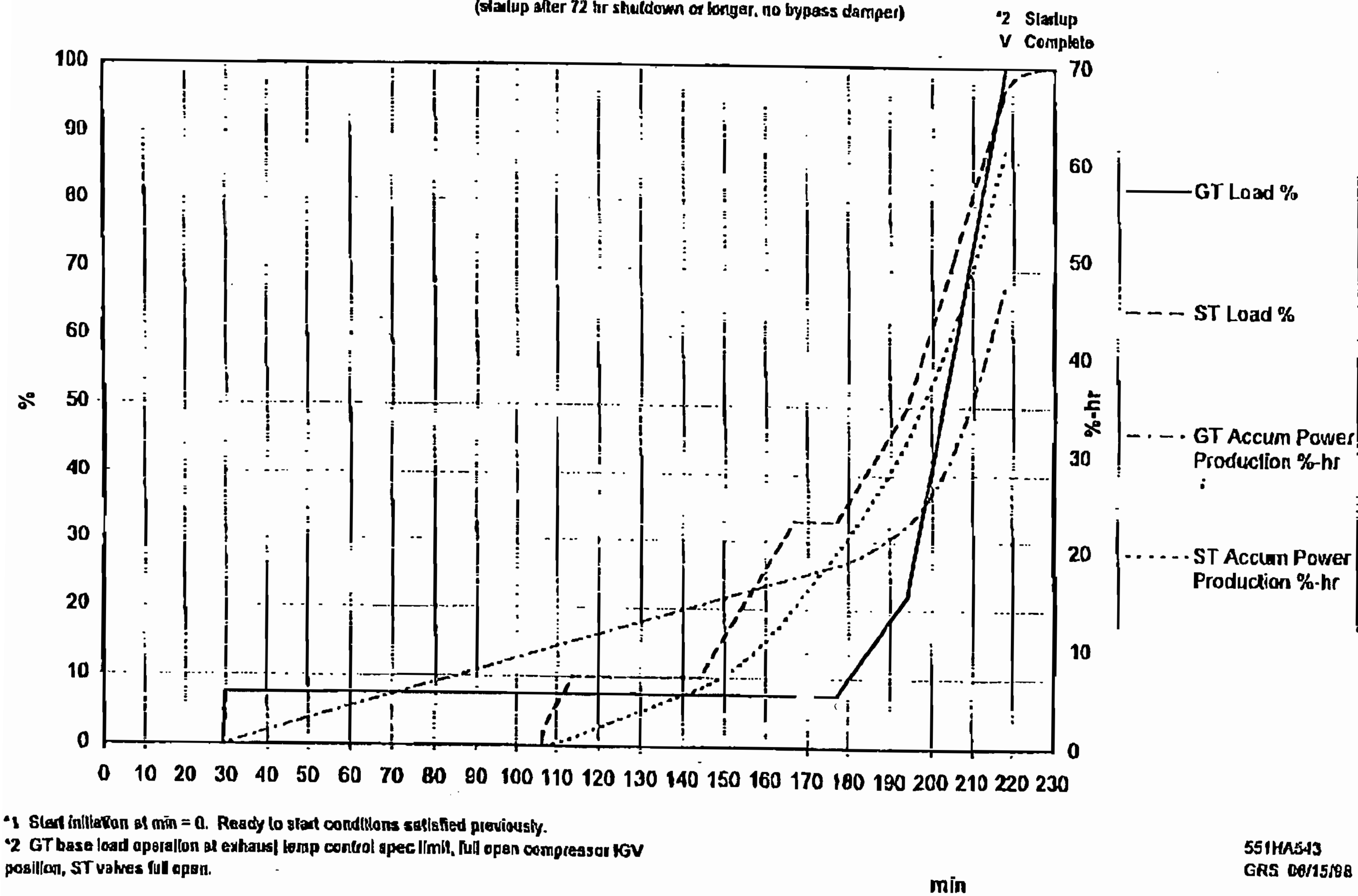
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA542
GRS 06/15/98

Best Available Copy

Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)



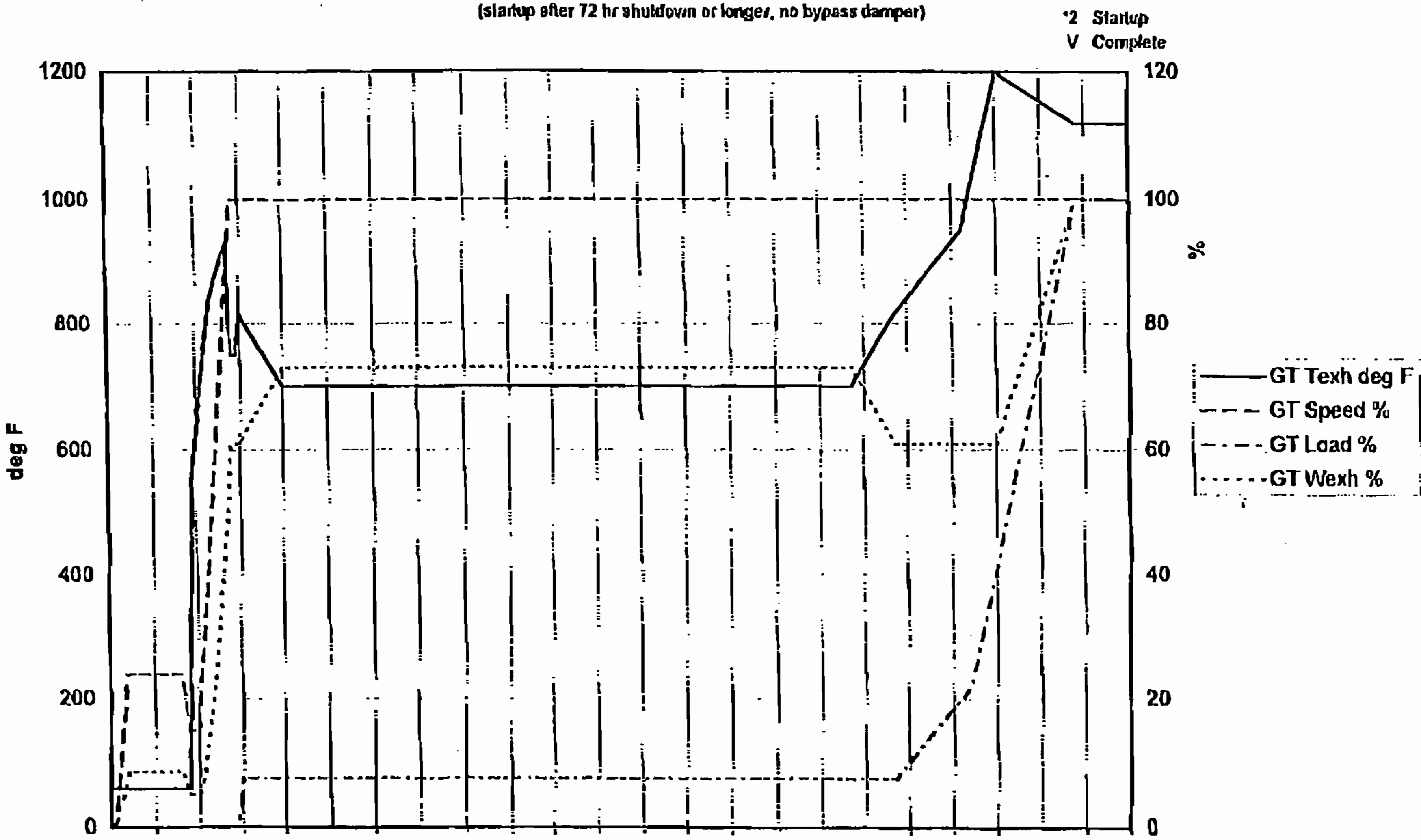
*1 Start initiation at min = 0. Ready to start conditions satisfied previously.
*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA543
GRS 06/15/98

Best Available Copy

Typical 107FA Coldstart (multishaft)

(startup after 72 hr shutdown or longer, no bypass damper)

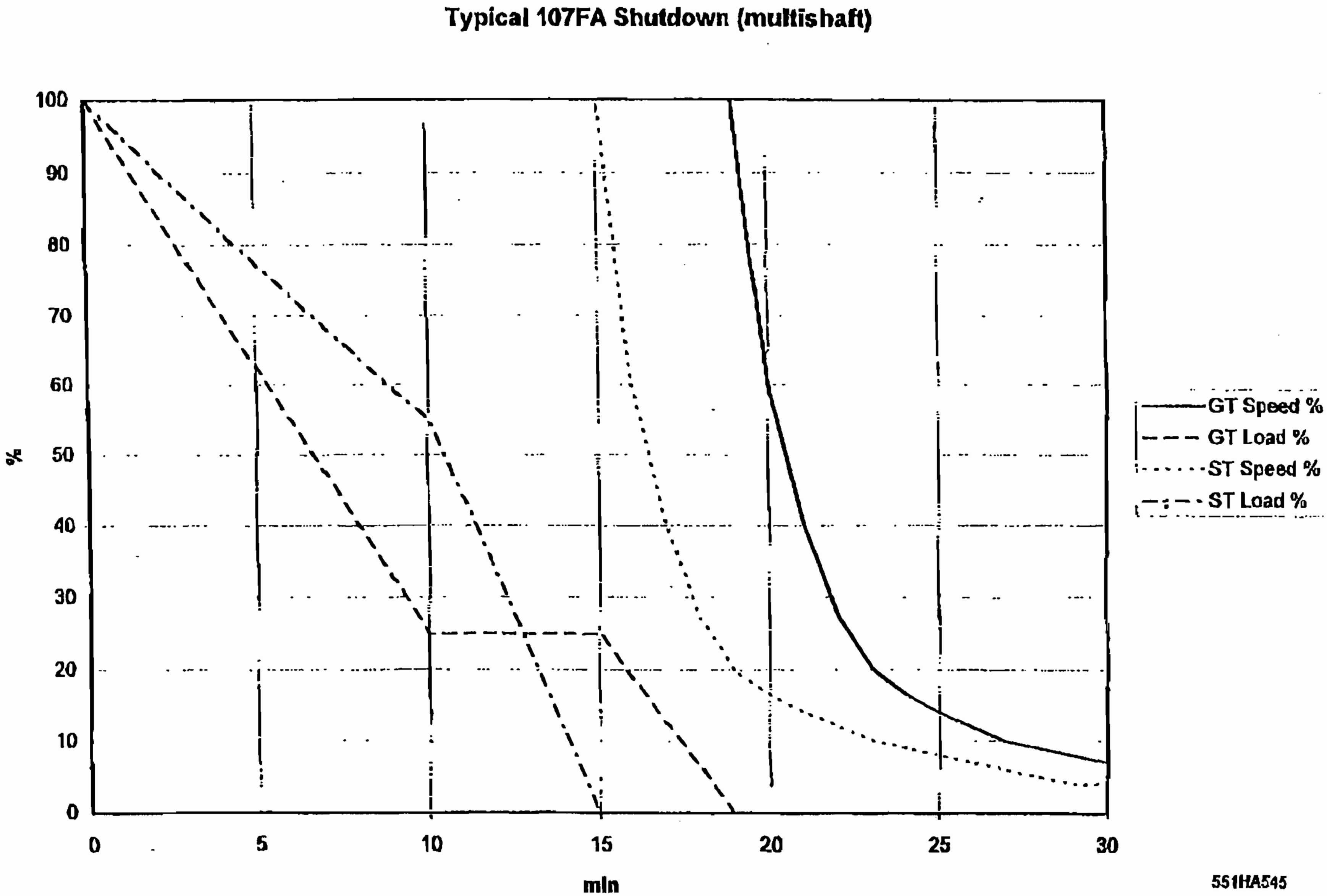


*1 Start Initiation at min = 0. Ready to start conditions satisfied previously.

*2 GT base load operation at exhaust temp control spec limit, full open compressor IGV position, ST valves full open.

551HA544
GRS 06/15/98

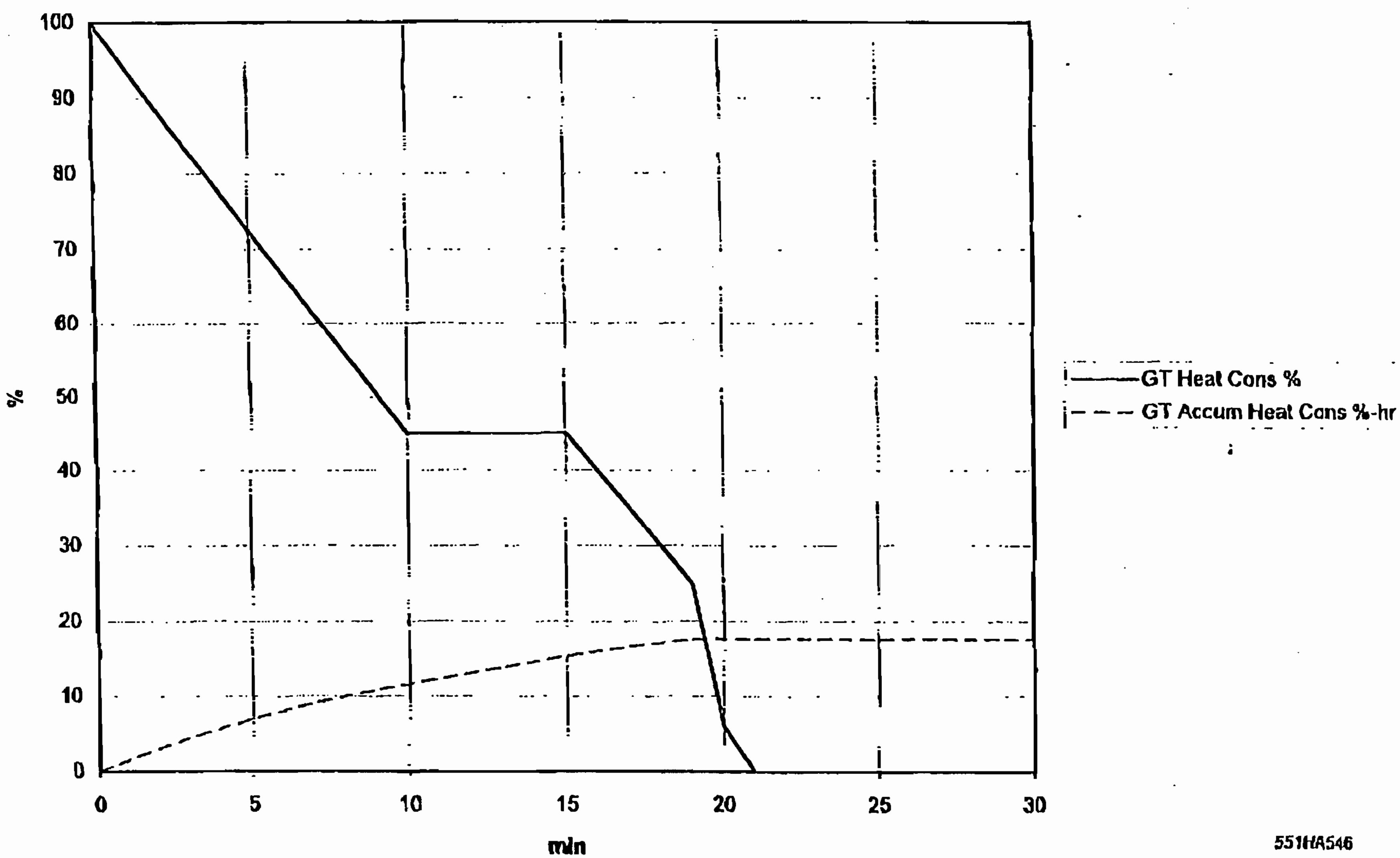
Best Available Copy



551HA545
GRS 08/15/98

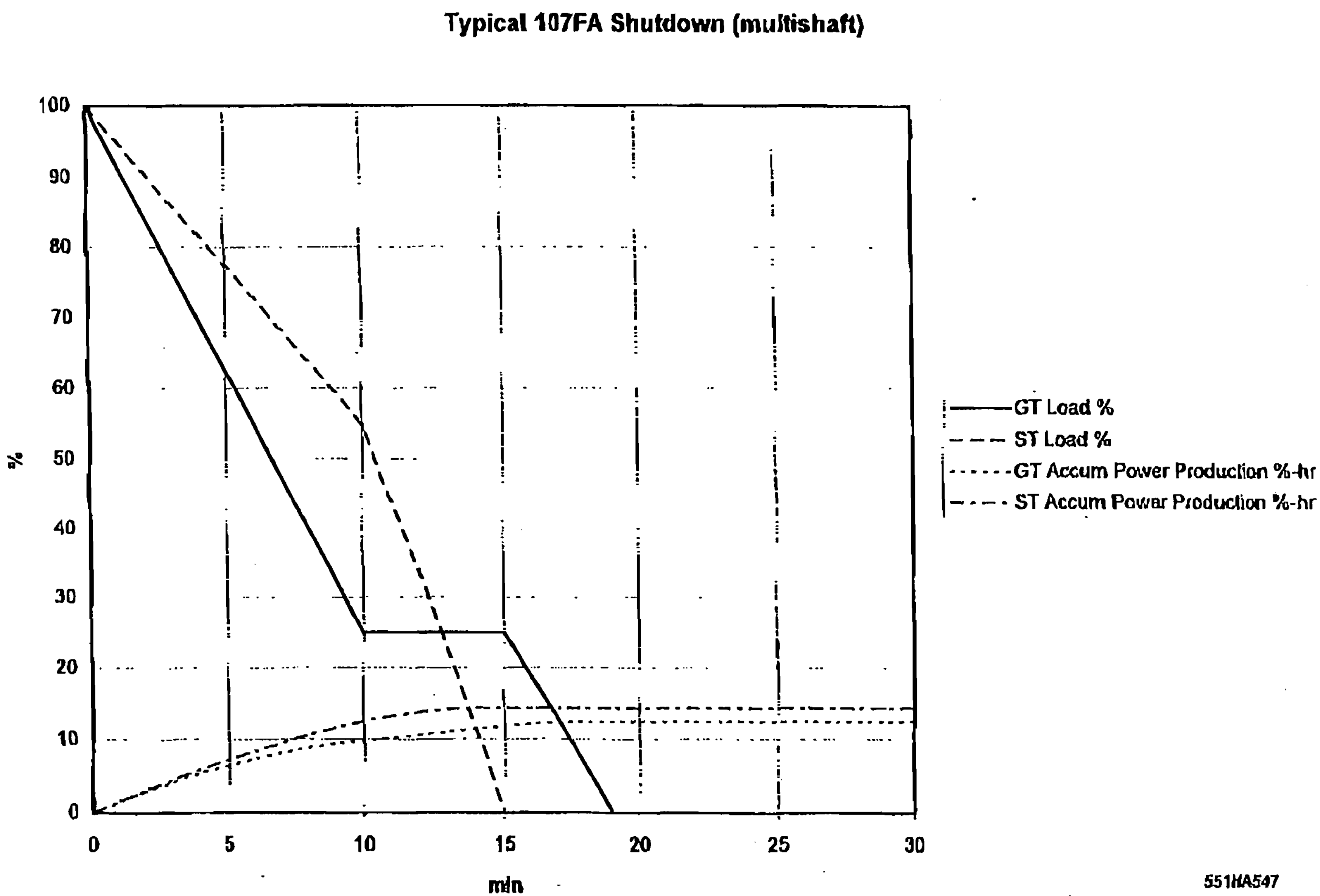
Best Available Copy

Typical 107FA Shutdown (multishaft)



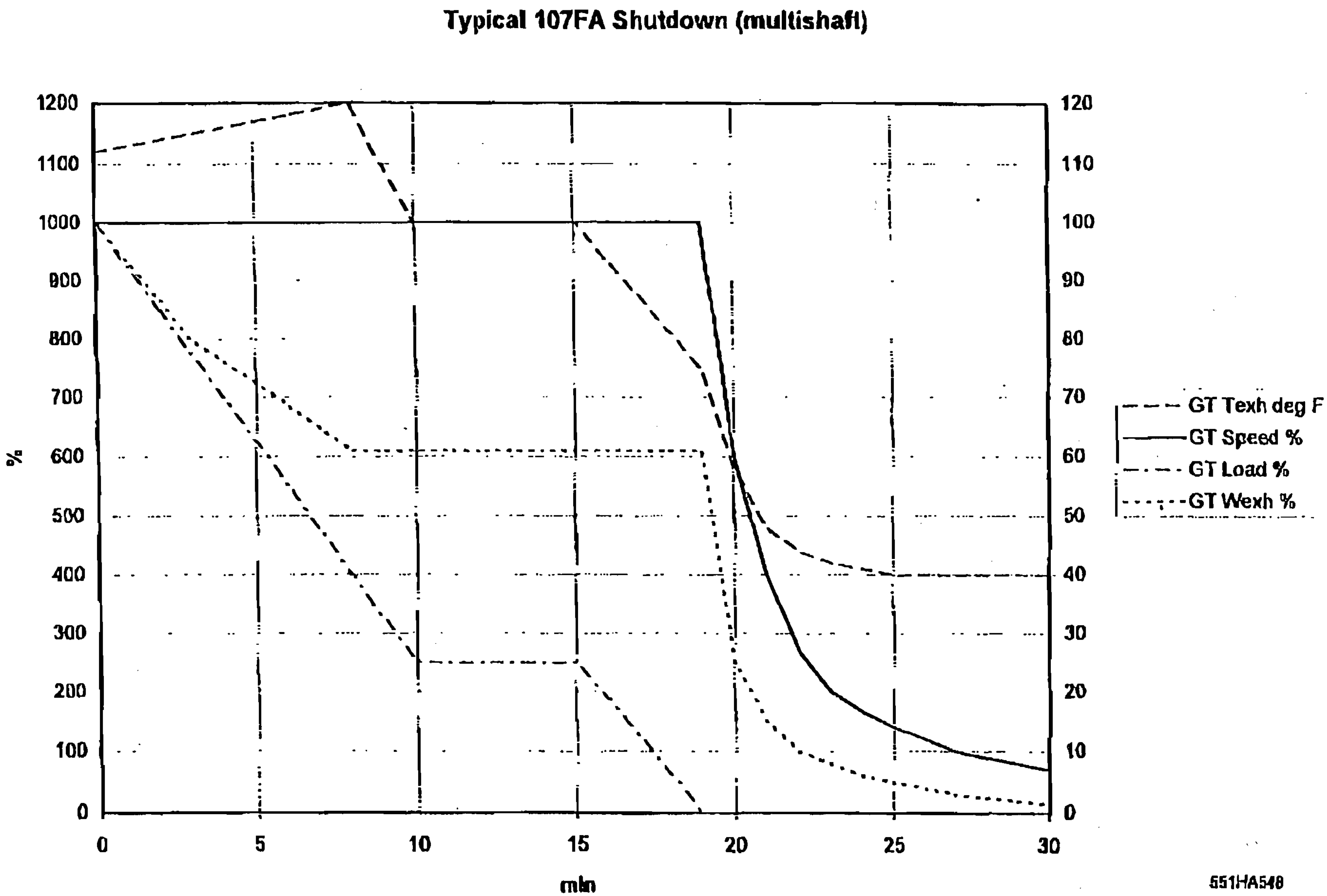
551HA546
GRS 06/15/98

Best Available Copy

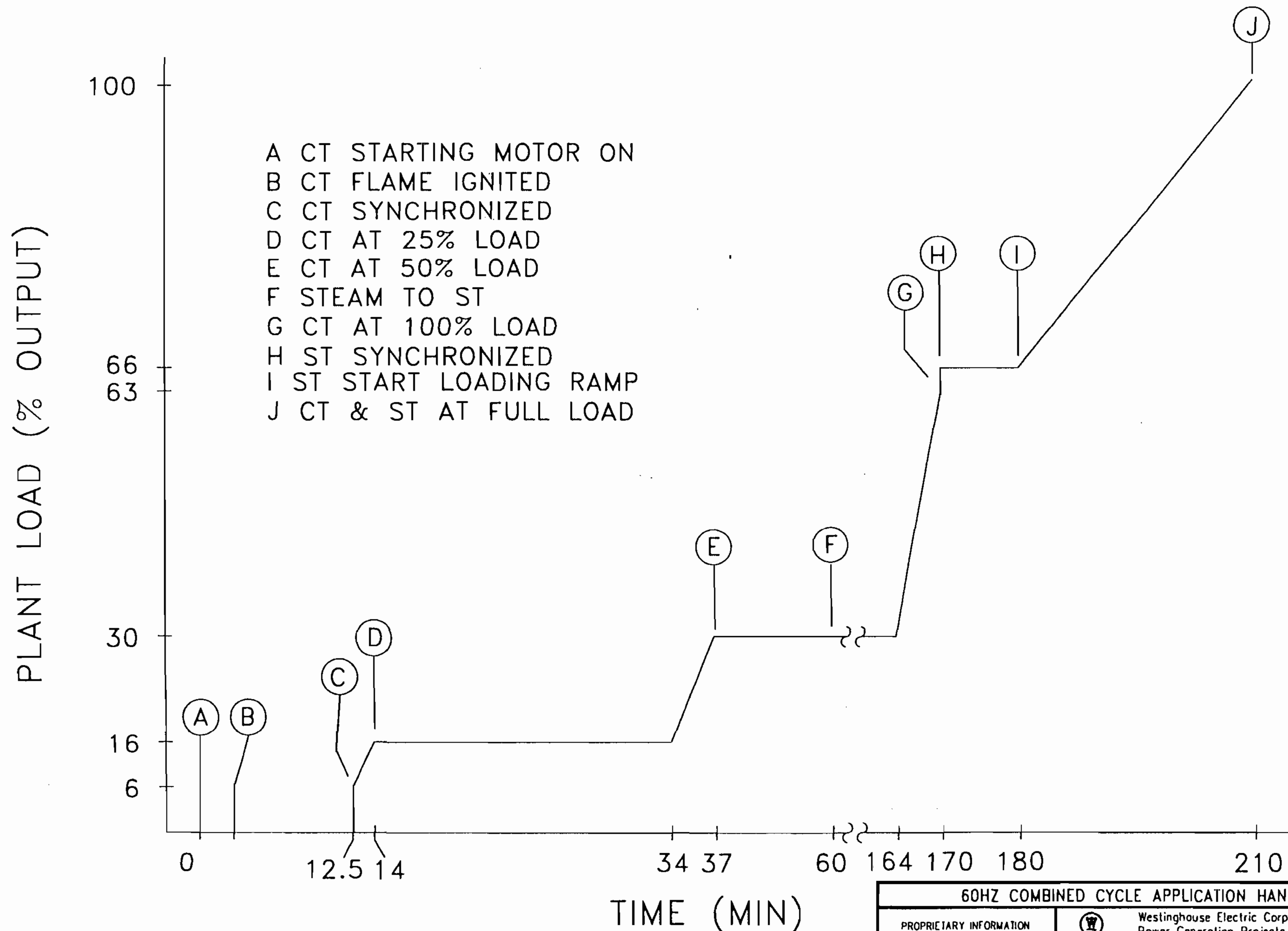


551HA547
GRS 06/15/98

Best Available Copy



551HA548
GRS 06/15/98



60HZ COMBINED CYCLE APPLICATION HANDBOOK

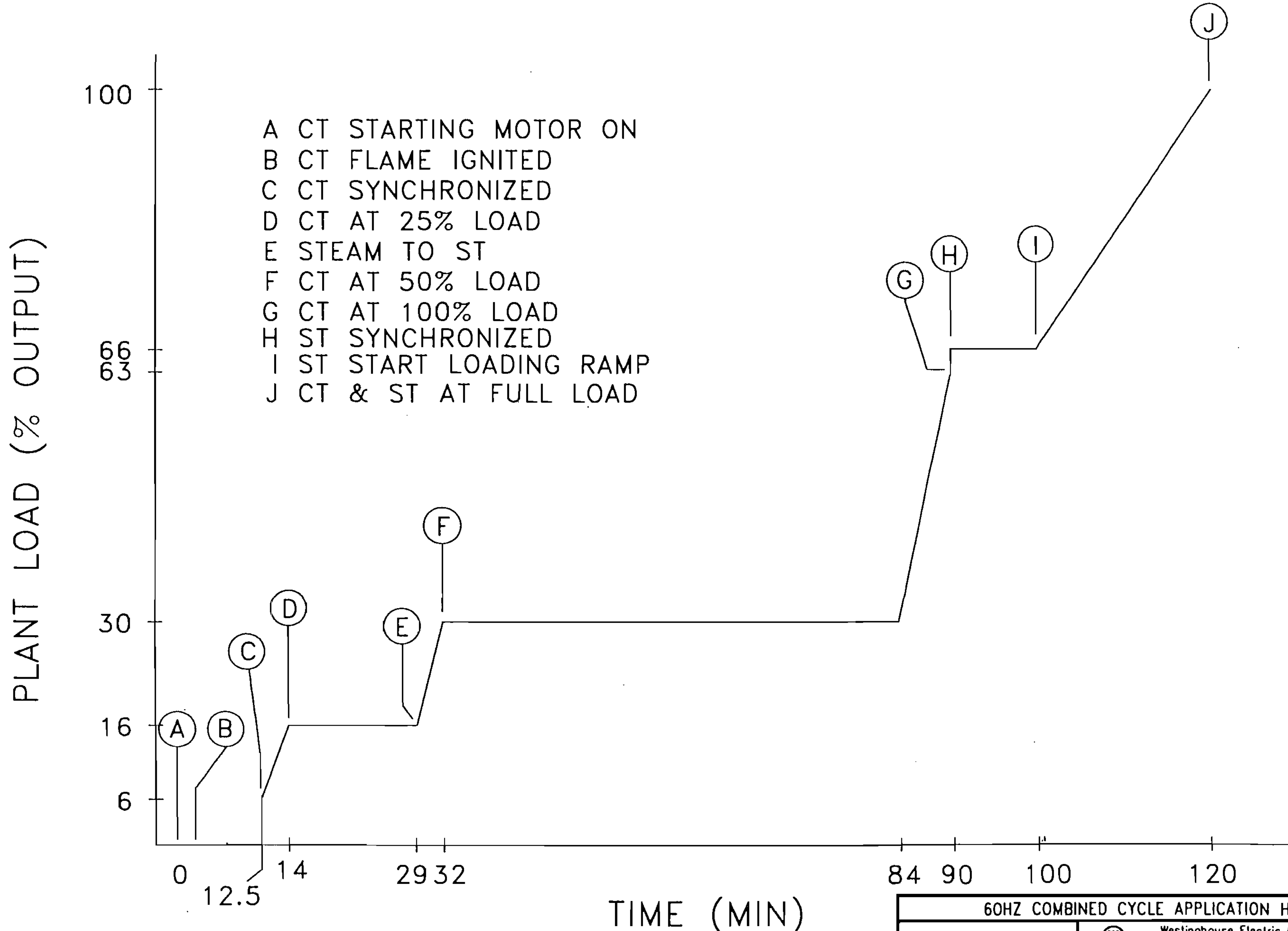
PROPRIETARY INFORMATION

Westinghouse Electric Corporation
Power Generation Projects Division

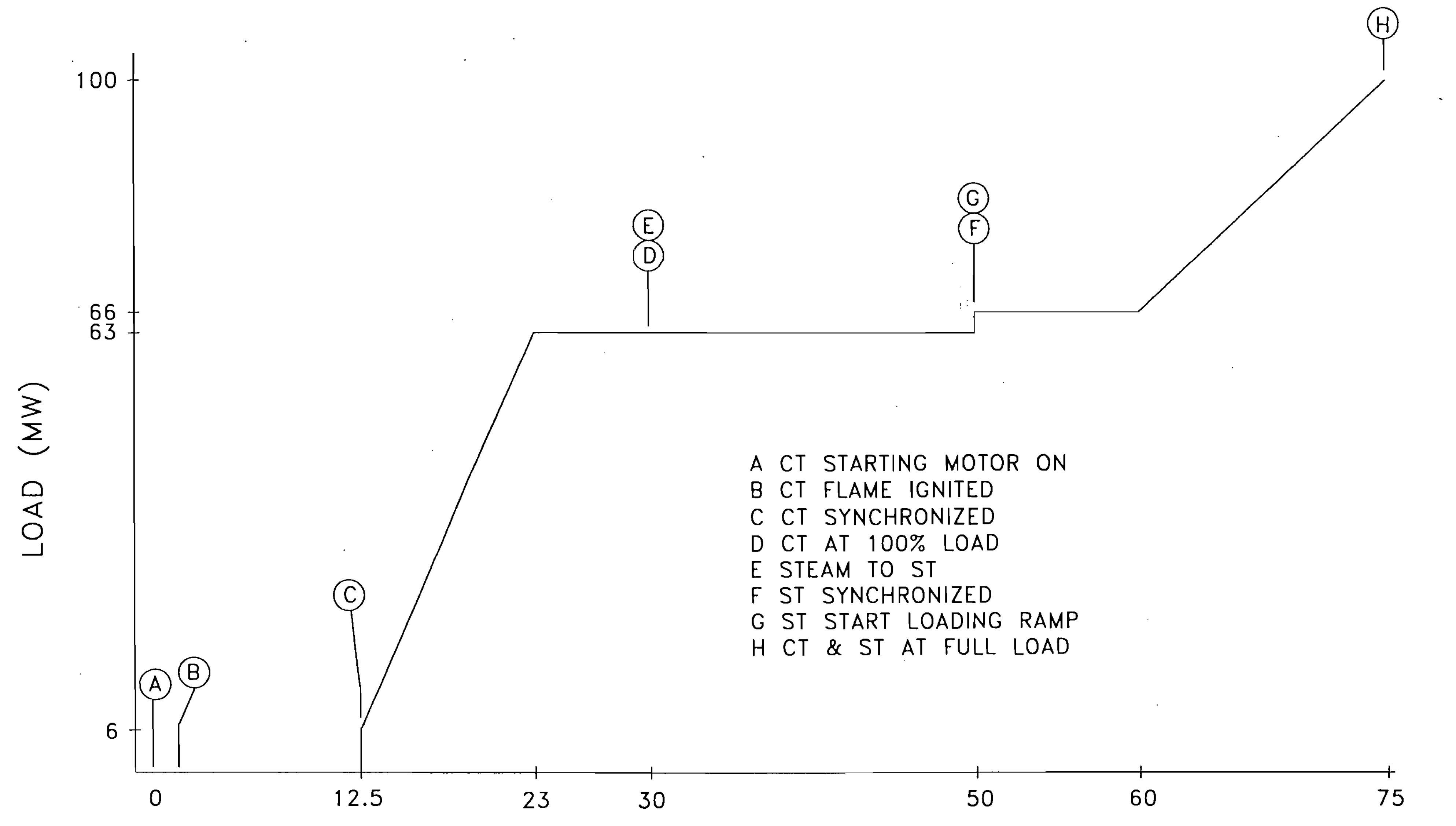
DATE 09/15/94 | DRAFTER L. MONROE
ENGINEER M W ONAITIS
APPROVED BY

1X1 COMBINED CYCLE PLANT
TYPICAL COLD START LOAD (PROFILE)
(72 HOUR SHUTDOWN)

CUST NO. 94505 | Drawing No. V1860601 | Page 1 of 1



60HZ COMBINED CYCLE APPLICATION HANDBOOK	
PROPRIETARY INFORMATION	Westinghouse Electric Corporation Power Generation Projects Division
DATE 09/15/94 · DRAFTER L. MONROE ENGINEER M W ONAITIS APPROVED BY	1X1 COMBINED CYCLE PLANT TYPICAL WARM START LOAD (PROFILE) (48 HOUR SHUTDOWN)



60HZ COMBINED CYCLE APPLICATION HANDBOOK

PROPRIETARY INFORMATION

Westinghouse Electric Corporation
Power Generation Projects Division

DATE 09/15/94 | DRAFTER L. MONROE
ENGINEER M W ONAITIS MO
APPROVED BY MX

1X1 COMBINED CYCLE PLANT
TYPICAL HOT START LOAD (PROFILE)
(8 HOUR SHUTDOWN)

CUST NO 84505 | Drawing No V1860401 | ISSUE | Page 1 of 1

AL

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

RECEIVED

AUG 13 1998

BUREAU OF
AIR REGULATION

4APT-ARB

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

RECEIVED

AUG 11 1998

AIR AND RADIATION TECHNOLOGY BRANCH
EPA - REGION 4
ATLANTA, GA

SUBJ: PSD Permit Application from Santa Rosa Energy Center, Sterling Fibers Manufacturing Facility, Pace, Florida (PSD-FL-253)

Dear Mr. Fancy:

Thank you for your letter of July 9, 1998, submitting an application for a Prevention of Significant Deterioration (PSD) permit for the Santa Rosa Energy Center in Pace, Florida. The application is for the installation of a combustion turbine combined cycle cogeneration facility which will be located within the Sterling Fibers Inc. plant boundary. The facility will provide steam and electricity to Sterling Fibers and electricity to the electric utility grid. The proposed cogeneration facility will consist of a combustion turbine (CT) generator, a heat recovery steam generator (HRSG) equipped with a duct burner, a steam turbine generator, and associated auxiliary equipment. The combustion turbine and duct burner will only fire natural gas. The CT will be a General Electric (GE) Frame 7F design or equivalent with an electric generation capacity of approximately 168 MW. The duct burner will be rated at 585 mmBtu/hr. A fuel input limit is proposed for the duct burner of 3,280 x 10^6 scf/yr of natural gas. When additional electric generating capacity is needed for short periods of time, power augmentation will be used.

The proposed best available control technology (BACT) for NO_x control for the CT consist of the use of dry low NO_x (DLN) combustion to maintain emissions at no greater than 9 ppmvd during normal operation and no greater than 12 ppmvd during power augmentation. The duct burner will be equipped with a low NO_x burner to achieve an emission rate of 0.08 lb/mmBtu. The proposed BACT for PM/PM_{10}, volatile organic compounds (VOCs), and CO consists of the use of good combustion practices and clean burning fuels.

Based on our review of the application package, we have the following comments:

(1) The application indicates the CT will typically be operated at or near 100% of the design capacity, and the NO_x

emission rate from the CT will be 9 ppmvd during such conditions. Power augmentation will be used to operate the CT beyond normal operating mode design specifications for short periods of time when additional electric generating capacity is needed. During the power augmentation mode, the NO_x emissions may increase up to 12 ppmvd. As stated in the application, the CT manufacturer does not recommend operation in the power augmentation mode for extended periods of time.

Although operation in the power augmentation mode will apparently be limited, the worst case emissions from the Santa Rosa Energy project are based on operation of the facility 8,760 hours per year in the power augmentation mode with NO_x emissions of 12 ppmvd. The cost estimate of using selective catalytic reduction (SCR) for the control of NO_x emissions is also based on full time operation in the power augmentation mode, and the resulting control cost estimate is $5,247/ton, based on a 46% control efficiency to achieve 6 ppmvd. If the maximum amount of time that power augmentation can or will be used at the facility is known, this amount of time may be proposed as a permit restriction. A more accurate estimate of the worst case emissions for the project may then be based on NO_x emissions from the CT of 9 ppmvd during normal operation and 12 ppmvd during the maximum allowed operating time using power augmentation. This scenario of the worst case emissions should result in a more accurate estimate of the cost of using SCR at the facility.

(2) The lowest BACT NO_x emission limit recently proposed for facilities similar to the Santa Rosa Energy Center is an emission limit of 3.5 ppmvd achieved with the use of SCR. One of these projects is a major modification which has recently been proposed for the Alabama Power - Plant Barry facility in Bucks, Alabama, which consists of the construction of three new combined-cycle electric generating units, each of which will include a GE Model 7FA combustion turbine, or equivalent. The CTs and duct burners will only burn natural gas. The proposed BACT for NO_x emissions from each CT/HRSG at Plant Barry is the use of a dry low-NO_x combustor in the CT, a low-NO_x burner in the duct burner, and an SCR system installed within the HRSG to achieve a concentration of 3.5 ppmvd. Another facility, Mississippi Power - Plant Daniel, in Escatawpa, Mississippi, has recently submitted a PSD application for the construction of two new combined-cycle electric generating units, which will include two GE Model 7FA CTs. The CTs and duct burners will only fire natural gas. For each CT/HRSG at Plant Daniel, it is proposed that NO_x emissions will be controlled by the use of a DLN combustor in the CT, a low-NO_x burner in the duct burner, and a SCR system installed within the HRSG to achieve a concentration of 3.5 ppmvd. Since the BACT evaluation portion of a PSD application must include a consideration of the most stringent emission limit developed for similar facilities, the PSD application for the Santa Rosa Energy Center needs to include an

evaluation of the feasibility of achieving a NO_x emission concentration of 3.5 ppmvd with the use of SCR.

The regulations at 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines will be applicable to the new combustion turbine. 40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units will apply to the duct burner.

Thank you for the opportunity to review and comment on the application package. If you have any questions, please contact Keith Goff of my staff at (404)562-9137.

Sincerely yours,

Douglas Neeley

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

cc: NPS
NWD
M.E. Cramer, PE
C. Carson, SRE

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.

06 AUG 1998

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. James Shield, VP
Santa Rosa Energy LLC
650 Dundee Rd, Suite 150
Northbrook, IL 60062

4a. Article Number
P 265 659 399

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

7. Date of Delivery 8-6

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

Thank you for using Return Receipt Service.

P 265 659 399

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

Sent to	James Shield
Street & Number	Santa Rosa Energy
Post Office, State, & ZIP Code	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	8-3-98 113003-005 AC POD-FI-253

PS Form 3800, April 1995

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

August 3, 1998

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James Shield
Vice-President
Santa Rosa Energy LLC
650 Dundee Road, Suite 150
Northbrook, Illinois 60062

Re: DEP File No. 1130003-005AC (PSD-FL-253)
Santa Rosa Energy Center-241 MW Cogeneration Plant

Dear Mr. Shields:

The Department has conducted a completeness review of the Santa Rosa Energy Center's application received on July 8, 1998 for installation of a 241 megawatt GE MS 70001FA (or equivalent) combined cycle combustion turbine to be located within the boundaries of the Sterling Fiber Inc. Plant. Please provide responses to our comments and questions as follows:

Your application states the steam electric turbine associated with the HSRG will be less than 75 MW, however an exact number was not provided. We need reasonable assurance that this new project is not an electrical power plant as defined in the Florida Electrical Power Plant Siting Act. We would forward a copy of your reasonable assurance statement to the Department's Office of Siting Coordination to confirm that this construction project does not constitutes a new project or modification with respect to the Act. Please contact Mr. Buck Oven, P.E., at 850/487-0472 if you have any questions about this issue.

1. Power augmentation will allow the firing of additional natural gas while injecting water/steam into the turbine, to produce more megawatts. Explain the overall operation in the power augmentation mode. What technology is used to generate extra power (i.e., steam or water injection)? How much more power output is due to operation in the power augmentation mode. Provide an schematic of the power augmentation operation mode. What is the maximum manufacturer's recommended period (hr/year, hr/month) for operation in the power augmentation mode.

2. Does Sterling Fibers Inc. have ownership on this project or simply a contract for steam? This information will allow us to determine if the facility requires a separate identification number in our database (ARMS system).

3. Submit General Electric performance data sheets for this turbine and the HRSG's manufacturer performance sheets.

4. Expand on the details (G.E. papers, etc.) of the G.E Dry Low NOx burner technology and the Mark V control system.

5. Provide emission calculations under the normal operating scenario (excluding the power augmentation operation mode). What is the heat rate of this project (Btu/kwh)?

6. What is the total megawatts generated from steam (only)? Is the total power output capacity of the cogeneration plant 241 MW?

7. The Department acknowledges your request for authorization in accordance with Rule 62.210.710 F.A.C., to allow for excess emissions beyond the regulatory limit during periods of startup/shutdown and power augmentation periods. As this is the case, submit specific details about the frequency of these periods. Attach manufacturer support data.

Please submit the application information on an ELSA disk. This will facilitate the input of the application data in the Department's ARMS system.

We will forward any comments from the Department of Interior and EPA Region IV as soon as they are received. If you have any questions regarding this matter, please contact Teresa Heron (review engineer) or Cleve Holladay (meteorologist) at 850/488-1344.

Sincerely,

A A Linero 8/3

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

AAL/th

cc: Brian Beals, EPA
John Bunyak, NPS
Ed Middleswart, NWD
Mark Eugene Cramer,PE, Roy F. Weston, Inc
Craig Carson, Santa Rosa Energy LLC

SANTA ROSA *ENERGY* LLC

650 Dundee Road, Suite 150
Northbrook, Illinois 60062
Telephone (847)559-9800
Facsimile (847)559-1805

July 6, 1998

RECEIVED
JUL 08 1998
BUREAU OF
AIR REGULATION

Mr. A.A. Linero
Administrator, New Source Review Section
State of Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road., MS #5505
Tallahassee, Florida 32399-2400

1130003-005-AC
PSD-FL-253

Subject: Santa Rosa Energy Center
PSD Permit Application

Dear Mr. Linero:

Santa Rosa Energy LLC is pleased to submit a PSD Permit Application for a new combined cycle cogeneration facility to be constructed at Sterling Fiber's manufacturing facility in Pace, Florida. The Santa Rosa Energy Center will provide energy to Sterling Fiber's facility and will consist of a combustion turbine with a supplementary fired heat recovery steam generator and associated support facilities.

The PSD Permit Application package for the proposed cogeneration facility includes the necessary documentation for your review and analysis. The permit application includes the following sections:

Introduction
Project Description
Emissions Inventory
Regulatory Assessment
Best Available Control Technology Review
Air Quality Modeling Analysis
Application Forms
Sample Calculations
Vendor Information

We respectfully request that the construction permit for the proposed cogeneration facility described in this application be reviewed and processed in an expeditious manner. We would appreciate your efforts to issue the requested permit by October 1, 1998.

Should you have any questions concerning this application, please contact Mr. Craig Carson at (847) 559-9800 extension 325.

Sincerely,

SANTA ROSA ENERGY LLC,
By its Managing Member
Polsky Energy Corporation

James J. Shield

James J. Shield
Vice President
Engineering and Project Management

Enclosure

CC: J. Neron
EPA
NPS
C. Holladay
NWO

POLSKY ENERGY CORPORATION
EDENS CORPORATE CENTER
650 DUNDEE ROAD, SUITE 150
NORTHBROOK, IL 60062-2753
PH. 708-559-9800

LA SALLE NATIONAL BANK
CHICAGO, ILLINOIS 60690
2-50-710

6869

DATE AMOUNT

Seven Thousand Five Hundred and 00/100

PAY
TO THE
ORDER
OF

06/26/98 $**********7,500.00

Dept. of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Rd.MS #5505
Tallahassee,FL 32399-2400

Security features included. Details on back.

091175/7-95

[redacted]

RECEIVED

MAR 02 1998

BUREAU OF
AIR REGULATION

WESTON
MANAGERS DESIGNERS/CONSULTANTS

Roy F. Weston, Inc.
1 Weston Way
West Chester, Pennsylvania 19380-1499
610-701-3000 • Fax 610-701-3186

24 February 1998

Mr. Al Linero, PE
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Work Order No. 11596-001-001

Dear Mr. Linero:

Roy F. Weston, Inc. (WESTON®) is submitting the following air quality modeling protocol for review by the Florida Department of Environmental Protection (DEP). The air quality modeling protocol describes the technical approach and procedures that will be applied as part of an air quality impact demonstration for the Santa Rosa Energy Center at the Sterling Fibers facility in Milton Florida. The protocol is based on U.S. EPA guidance contained in 40 CFR Part 51 Appendix W, and additional DEP guidance provided by Mr. Tom Rogers.

PROJECT DESCRIPTION

Santa Rosa Energy LLC, a subsidiary of Polsky Energy Corporation of Northbrook, Illinois, is proposing to construct and operate a gas turbine combined cycle cogeneration facility to supply energy in the form of steam and electricity to Sterling Fibers, Inc. (Sterling Fibers) in Santa Rosa County, Florida. The Sterling Fibers plant is located near Milton, Florida. The location of the cogeneration facility which is adjacent to the Sterling Fibers plant is shown on Figure 1.

The primary components of the cogeneration train will be a combustion turbine, a heat recovery steam generator (HRSG) equipped with a duct burner, and a steam electric turbine. The combustion turbine will be a General Electric Frame 7F design or equivalent with an electric generation capacity of 178 MW at average ambient temperature and 60% humidity conditions. The combustion turbine will be fired with natural gas. The combustion turbine will be equipped with a Dry Low NO_X Combustor for natural gas firing to limit NO_X emissions to 9 ppmdv at 15% O_2 under normal operating conditions. The duct burner will be rated at 585 MMBtu/hr, however, Santa Rosa Energy LLC is taking a permit limit to restrict the average annual fuel input to 375 MMBtu/hr. The duct burner will be fired with natural gas and will be manufactured by Coen or equivalent and will be a low NO_X design. The HRSG will be a triple pressure unit providing most of its high pressure steam to the Sterling Fibers header for electric generation at the Sterling Fibers power plant and subsequent process use. The remainder of the high pressure steam, and all intermediate pressure steam will be diverted to the steam turbine. Low pressure steam will be used within the cogeneration facility primarily for the HRSG deaerator. The combustion turbine and duct burner will not operate independently.

FACILITY LOCATION

The cogeneration facility is located near Milton, Santa Rosa County, FL. The host facility is surrounded by undeveloped land. The proposed cogeneration facility will be located to the south of the Sterling Fiber facility. A plot plan showing the exact location of the proposed project relative to the Sterling Fibers facility and the surrounding area is provided as Figure 2. The base elevation at the proposed location is 100 feet (ft) above mean sea level (amsl). The Universal Transverse Mercator (UTM) coordinates for the proposed cogeneration facility are:

488,970 meters Easting
3,381,390 meters Northing
UTM Zone 16

Within 3 km of the site the area is relatively flat with terrain fluctuations of 50 ft or less. As a result, the air quality modeling analysis will not incorporate terrain elevations as part of the study.

EMISSION CHARACTERISTICS

The pollutant emission rates for oil firing and natural gas firing are shown in Table 1. The emission rates include both the turbine and duct burner at 100% load.

The physical stack characteristics and the anticipated emission rates for the cogeneration facility are provided in Table 2. The emission characteristics that are provided in Table 2 reflect the 100%, 75%, 65% and 50% load condition at three different ambient temperatures. In order to confirm that the 100% load condition is the "worst-case" operating scenario from the perspective of air quality impacts, alternate load conditions will need to be evaluated. The emission rates shown in Table 1 will be proportionally adjusted to reflect the operating condition.

Any air toxics emissions from the cogeneration facility would be extremely low and when combined with the 200 ft stack height will likely result in very low ambient concentrations. Therefore, it is proposed that no air toxics modeling be performed.

AIR QUALITY MODELING AND DATA INPUT

The intent of the air quality modeling analysis is to demonstrate that the proposed cogeneration facility will have an insignificant impact, as defined by U.S. EPA significance levels, on the surrounding air quality. In order to accomplish this demonstration, the Industrial Source

Complex Short-Term 3 (ISCST3 Version 96113) will be used to predict the short-term and long-term impacts from the cogeneration facility. In addition to the ISCST3 model, the SCREEN3 model (Version 96043) will be used to select the worst case operating load condition and confirm air quality impacts in building cavities (if applicable). A brief description of the input data for each model and how each model will be used is provided in the following discussion.

Auer Land Use Determination

A land use analysis will be performed for the 3 km radius surrounding the proposed cogeneration facility. The land use analysis will be performed following the procedures described by Auer. United States Geological Survey (USGS) 7.5 minute topographic maps will be used for the land use determination. Based upon the land use determination, the appropriate dispersion option in the ISCST3 and SCREEN3 models will be used.

Topography

The topography surrounding the facility is generally flat. The base elevation of 100 ft above man sea level (amsl) and the stack height of 200 ft means that complex terrain begins at an elevation of 300 ft. There are no area within 20 km of the proposed facility that exceed the 300 ft stack height elevation and thus a complex terrain evaluation will not be performed. Additionally, since the immediate area surrounding the proposed cogeneration facility consists of terrain with elevations well below the stack height elevation, it will not be necessary to include terrain elevations for any receptors.

Receptor Grid

Receptor grids for the ISCST3 and SCREEN3 models will be prepared. The receptor grids will be based on USGS topographic maps. For the SCREEN3 air quality modeling, receptors and receptor elevations will be selected using the following approach:

Receptors will be selected relative to the source. Circles will be plotted at 100 m intervals extending out to 1,000 m, 200 m intervals from 1,000 m out to 2,000 m, 500 m intervals from 2,000 m out to 5,000 m, and 1,000 m intervals from 5,000 m out to 10,000 m.

For the ISCST3 receptor grid, a Cartesian coordinate system will be used. The ISCST3 receptor grid will consist of a rectangular grid with 20 km by 20 km dimensions which will be approximately centered on the cogeneration facility stack. The inner portion of the grid will have grid cells that include 100 m spacing out to 1,000 m. A 200 m spacing will extend out to 3,000 m, and a 500 m spacing will extend out to 5,000 m. From 5,000 m to 10,000 m, a 1,000 meter spacing will be used to develop the grid cells.

The ISCST3 receptor grid will include a subset of on-site receptors that are located within the plant boundary of the host facility but outside the fenceline of the host facility. Also, the portion of the host facility property line that is fenced or constitutes restricted access will be represented with discrete property line receptors.

METEOROLOGICAL DATA

The meteorological data that will be used in the air quality modeling will consist of screening meteorological data and five years of National Weather Service data. The SCREEN3 model uses a matrix of meteorological conditions to predict the worst case air impacts. For the ISCST3 air quality modeling, five years of NWS data from the Pensocala Regional Airport (1985-1989) will be used. Upper air meteorological data from Apalachicola, FL will be used to create mixing height data files. The Pensacola airport is 30 km to the southwest of the host facility and considered is representative of the meteorological conditions at the Sterling Fiber facility.

BUILDING DOWNWASH ANALYSIS

A Good Engineering Practice (GEP) stack height analysis will be performed to evaluate the potential for building aerodynamic downwash as well as the presence of cavity zones. The GEP analysis will be performed using plot plans and information provided by personnel at the host facility. All structures associated with the cogeneration facility as well as all structures at the host facility will be included in the downwind analysis. The U.S. EPA Building Profile Input Program (BPIP Version 95086) will be used to evaluate the potential for building downwash.

The stack height of the proposed cogeneration facility is 200 ft. Therefore, a building would have to have a minimum height of 80 ft in order to influence the cogeneration stack (i.e. 2.5 x L where L is height and is less than the building width). All of the buildings or structures that are higher than 80 ft will be identified. The BPIP input, output and a plot plan of the host facility will be provided to DEP for review.

SUMMARY OF AIR QUALITY MODELING RESULTS

The results of the air quality modeling analysis will be summarized and a comparison will be made to the PSD significance levels. The maximum short-term and long-term off-site air quality impacts will be used for the comparison. The results of the significance analysis will determine the need to perform additional multi-source air quality modeling.

A summary report will be prepared that describes the air quality modeling and shows the level of air quality impacts. A floppy disk with all input files and output files will be included with the summary report.

Mr. Al Linero, PE
Florida Department of
Environmental Protection

27 January 1998

WESTON is prepared to begin the air quality modeling for the proposed cogeneration facility immediately upon approval of the air quality modeling protocol. If you have any questions regarding the proposed modeling approach please call me at 610-701-7217 or Mr. Craig. Carson at Polsky Energy Corporation at 847-559-9800-Ext. 314.

Very truly yours,

ROY F. WESTON, INC.

Louis M. Militana, QEP
Project Manager

cc: T. Heron, BAR
C. Holladay, BAR

CORPO5|E:\FOLDERS.M-R\PEC\PEC065C.LTR

TABLE 1
SANTA ROSA COGENERATION CENTER
MAXIMUM HOURLY EMISSION RATES FROM THE COGENERATION SYSTEM
COMBUSTION TURBINE AND DUCT BURNER FIRING NATURAL GAS ONLY

POLLUTANT	COMBUSTION TURBINE EMISSIONS[a] (lb/hr)	DUCT BURNER EMISSIONS[b] (lb/hr)	TOTAL STACK EMISSIONS[c][d] (lb/hr)
Total Suspended Particulate[e]	9.0	4.7	13.7
Particulate Matter <10 microns[e]	9.0	4.7	13.7
Sulfur Dioxide	1.0	0.6	1.6
Nitrogen Oxides	82.0	46.8	128.8
Volatile Organic Compounds	15.0	11.1	26.1
Carbon Monoxide	30.0	46.8	76.8
Lead[f]	0	0	0
Sulfuric Acid Mist[e]	0	0	0
Beryllium[f]	0	0	0
Total HAPs[f]	0	0	0

[a] Emission rates for each pollutant are the highest hourly rates over the range of ambient air conditions and load levels for the combustion turbine as provided by the combustion turbine vendor. Refer to Table B-1.

[b] Based on full load conditions firing natural gas. Refer to Table B-1.

[c] Combustion turbine with duct burner will be exhausted through a single stack.

[d] Emissions from combustion turbine/duct burner systems operating simultaneously.

[e] Sulfuric acid mist emissions are not included with particulate matter emissions. There are no emission factors available for a combustion turbine or duct burner firing natural gas.

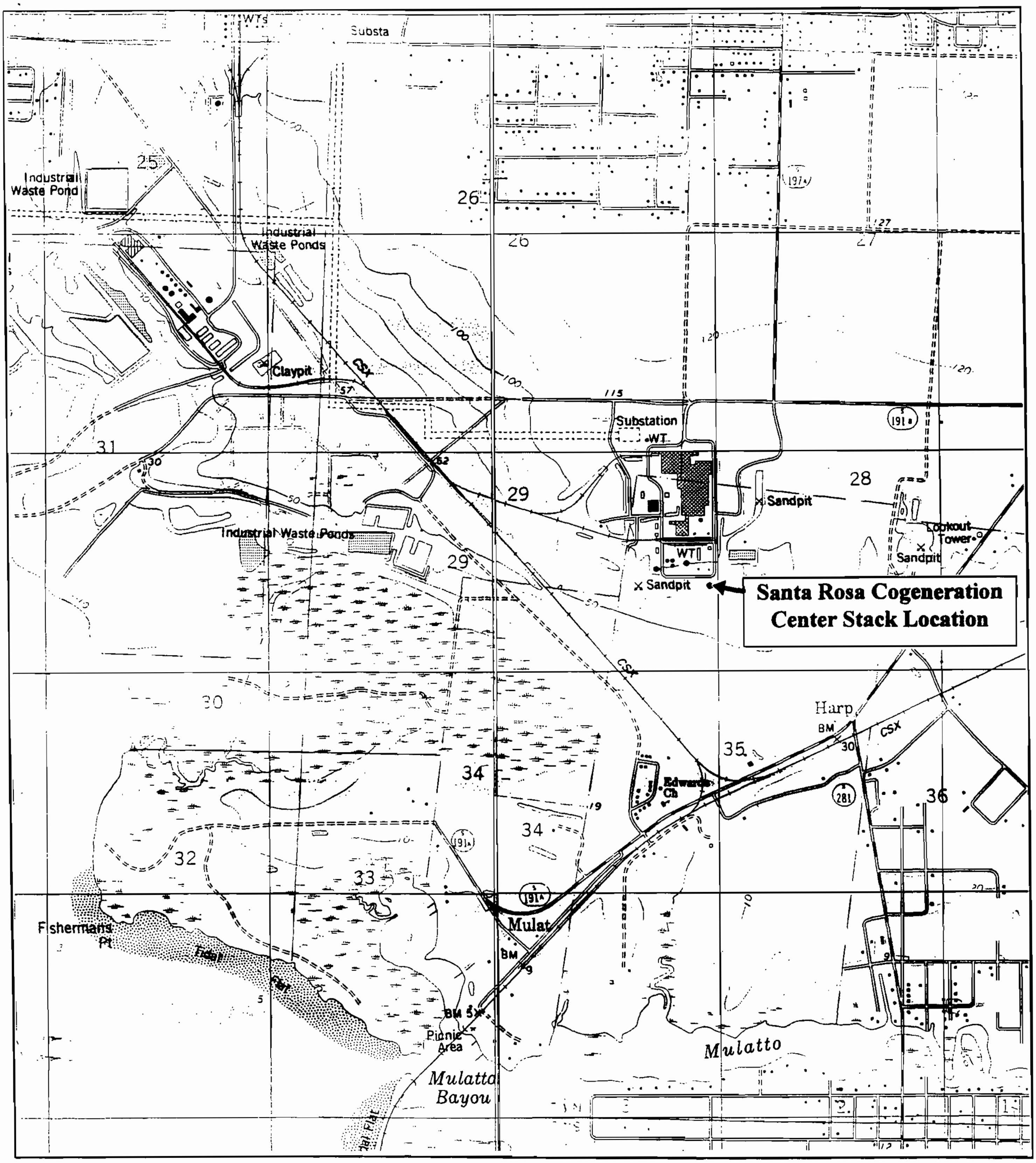
[f] No emissions factors for HAPs are available for natural gas firing for the combustion turbine and duct burner emissions. Natural gas emission factors for natural gas combustion in boilers are low quality and indicate trace quantities of HAPs. HAPs were assumed to be zero.

TABLE 2
POLSKY ENERGY CORPORATION
PROPOSED GAS TURBINE PROJECT
MILTON FACILITY
PHYSICAL STACK CHARACTERISTICS FOR MODELING
BASED ON THE FIRING OF NATURAL GAS

BASE LOAD	AMBIENT CLIMATE CONDITIONS	COMPRESSOR INLET TEMP. (°F)	EXHAUST FLOW (lb/hr)	GAS MOLECULAR WEIGHT (lb/lb-mol)	EXHAUST TEMP.[a] (°F)	EXHAUST TEMP. (°R)	EXHAUST FLOW (acfm)	EXHAUST VELOCITY[b] (ft/sec)	STACK DIAMETER[c] (ft)	STACK HEIGHT[d] (ft)	GAS COMPOSITION				
											O_2	CO_2	H_2O	N_2	Ar
100%	Winter[e]	40	3,656,000	28.5	202	661	1,033,562	79.6	16.6	200.0	12.48%	3.97%	7.86%	74.80%	0.89%
	Average[f]	68	3,507,000	28.3	202	661	995,596	76.7	16.6	200.0	12.28%	3.96%	8.94%	73.94%	0.88%
	Summer[g]	92	3,335,000	28.2	202	661	952,772	73.4	16.6	200.0	12.02%	3.91%	10.53%	72.67%	0.87%
75%	Winter	40	2,964,000	28.5	202	661	837,749	64.5	16.6	200.0	12.58%	3.92%	7.77%	74.83%	0.90%
	Average	68	2,884,000	28.4	202	661	817,580	63.0	16.6	200.0	12.50%	3.88%	8.54%	74.20%	0.89%
	Summer	92	2,765,000	28.2	202	661	788,608	60.8	16.6	200.0	12.28%	3.82%	10.03%	72.99%	0.88%
65%	Winter	40	2,750,000	28.5	202	661	777,116	59.9	16.6	200.0	12.68%	3.88%	7.68%	74.87%	0.89%
	Average	68	2,685,000	28.4	202	661	761,101	58.6	16.6	200.0	12.61%	3.83%	8.44%	74.24%	0.88%
	Summer	92	2,587,000	28.2	202	661	737,694	56.8	16.6	200.0	12.40%	3.77%	9.93%	73.03%	0.87%
50%	Winter	40	2,442,000	28.5	202	661	689,803	53.1	16.6	200.0	12.90%	3.77%	7.49%	74.94%	0.90%
	Average	68	2,385,000	28.4	202	661	675,814	52.1	16.6	200.0	12.82%	3.73%	8.26%	74.31%	0.88%
	Summer	92	2,311,000	28.2	202	661	658,692	50.8	16.6	200.0	12.65%	3.65%	9.71%	73.12%	0.87%

[a] Provided by Polsky. Exhaust temperature assumed to be equal for all load conditions.
[b] Assumed exhaust velocity in order to "back-calculate" stack diameter for 100% baseload winter case while firing natural gas. Assume same diameter for all other cases.
[c] Stack diameter "back-calculated" based on assumed exhaust velocity.
[d] Stack height of 200 ft. determined based on engineering practice (GEP) stack height calculation.
[e] Represents January daily minimum temperature.
[f] Represents the annual average temperature.
[g] Represents average summer ambient climate conditions.

Best Available Copy



NORTH 0 1000 2000 4000 SCALE IN FEET 500 200 0 500 SCALE IN METERS SOURCE: Base map adapted from USGS 7.5 minute series quadrangles (1:24,000) Milton South and Pace, dated 1978, PR 1987.	**Santa Rosa Cogeneration Center** **Town of Milton, Santa Rosa County** **Florida** **FIGURE 1** **FACILITY LOCATION MAP**

Best Available Copy

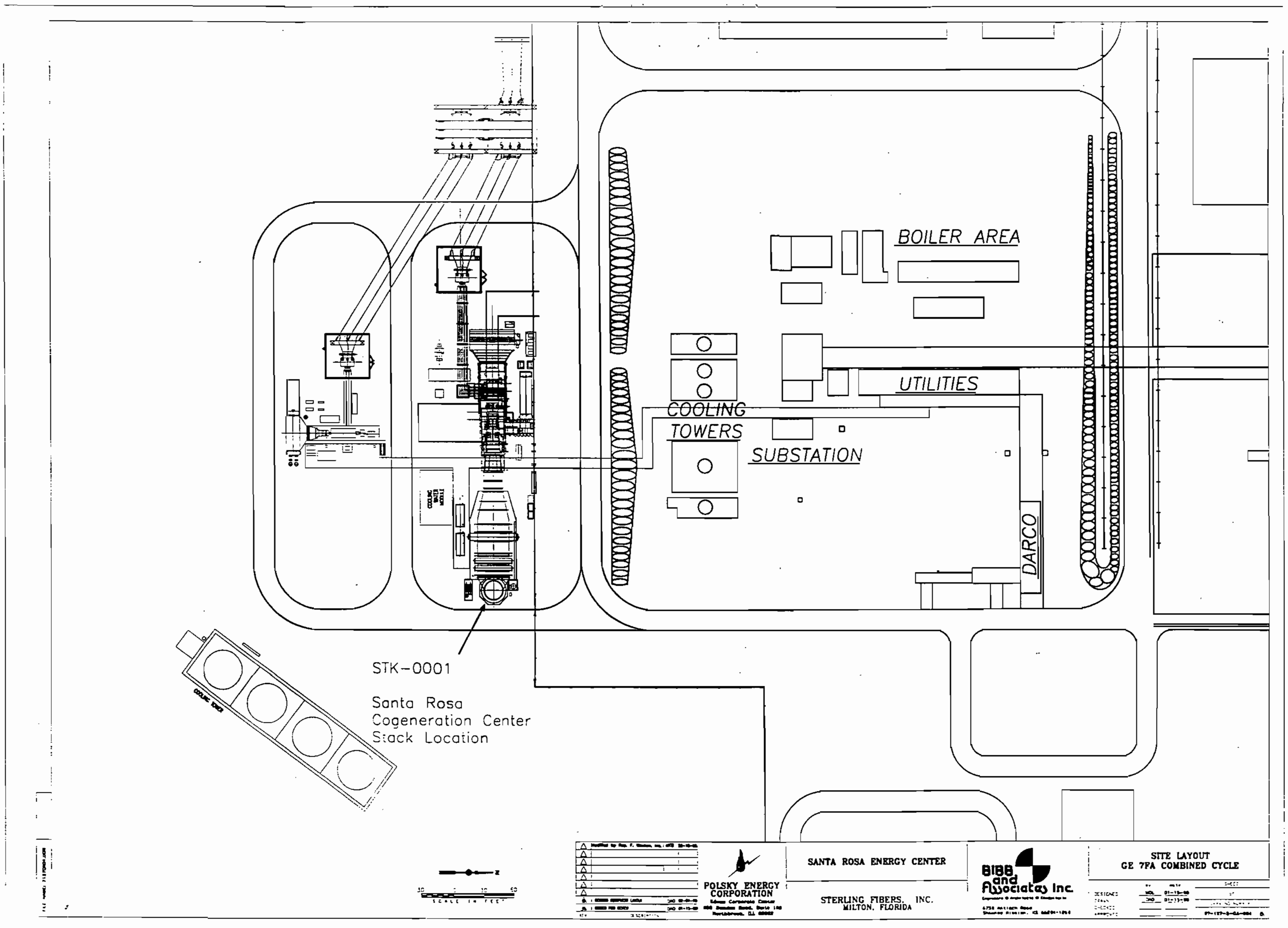


FIGURE 2

Determination Detail

Control Number: 9600034

Category: NSPS
EPA Office: Region 5
Date: 01/16/1996
Title: Custom Fuel Monitoring
Recipient: Wright, Amy
Author: Czerniak, George
Comments:

Abstract:

Q: Will EPA grant a request for a custom fuel monitoring schedule for (pipeline) natural gas fired turbines regulated by Subpart GG and Title IV (Acid Rain)?

A: Yes, this request is granted provided certain Acid Rain requirements are met.

Letter:

Amy Wright
Dayton Power and Light Company
O.H. Hutchings Station
9200 Chautauqua Road
Miamisburg, Ohio 45342

Dear Ms. Wright;

This is in response to your request for a custom fuel schedule, pursuant to the New Source Performance Standards (NSPS) Subpart GG, Section 60.334(b)(2), dated August 31, 1995. This request was originally sent to Donald Schregardus, Director, Ohio Environmental Protection Agency and later faxed to George Czerniak, United States Environmental Protection Agency (USEPA), Region 5, on September 9, 1995. In your request you proposed a custom fuel schedule under which no sampling of natural gas would be required for the combustion turbines installed, or to be installed under the Permit to Install application number 08-2507.

The three combustion turbines for which this custom schedule would apply are affected units under the "Acid Rain Program", Title IV of the Clean Air Act Amendments. Emissions from a Title IV effected unit are required to be monitored according to 40 CFR Part 75 "Continuous Emission Monitoring" for sulfur dioxide (SO2). Under Part 75, appendix D, a gas fired turbine that is using pipeline quality natural gas as it's primary fuel can use the default value of 0.0006 lb/mmBtu to account for the units SO2 emissions. With this the USEPA has recognized that the sulfur content of pipeline quality natural gas is low enough to warrant the use of a default value for SO2 emissions.

Therefore, the Regional office of the USEPA approves the custom fuel schedule of no fuel sampling for these three units provided the following requirements are met.

☐ Each unit has been issued and is in possession of an approved Phase II Acid Rain Permit.

☐ Each unit has submitted a Monitoring Plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas.

☐ Each unit is monitoring SO2 emissions using methods consistent with the requirements of Part 75 and certified by the USEPA.

This custom schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to anything other than this, SO2 emissions must be accounted for by using daily fuel sampling and analysis.

If you have any questions regarding this determination please contact Allan Batka of my staff at (312) 353-3716.

Sincerely yours,

George Czerniak, Chief
Air Enforcement and Compliance Assurance Branch

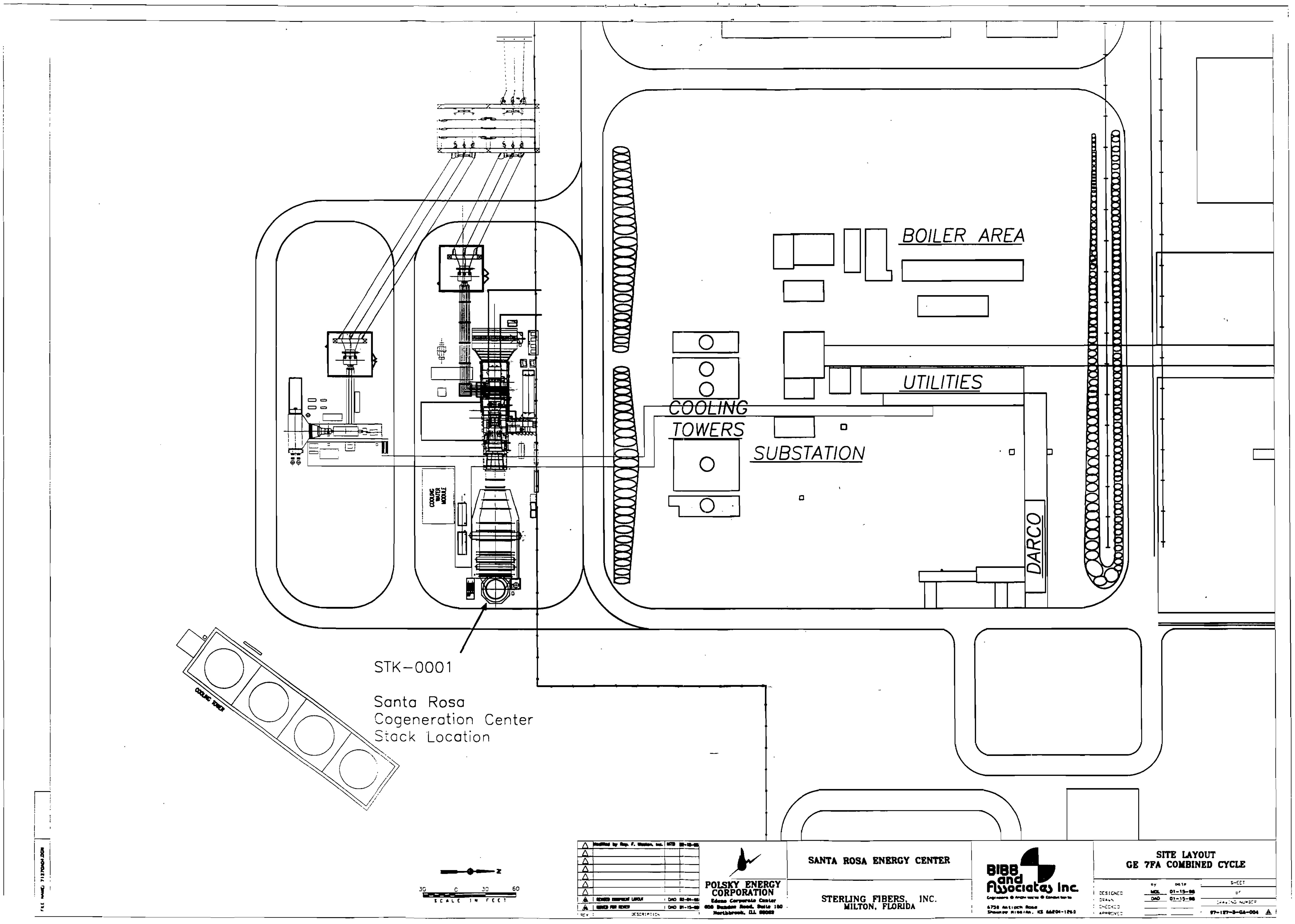


FIGURE 2

C:\nc\milton

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.

06 AUG 1998

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. James Shield, VP
Santa Rosa Energy LLC
650 Dundee Rd, Suite 150
Northbrook, IL 60062

4a. Article Number
P 265 659 399

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

7. Date of Delivery 8-6

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

Thank you for using Return Receipt Service.

P 265 659 399

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

Sent to	James Shield
Street & Number	Santa Rosa Energy
Post Office, State, & ZIP Code	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	8-3-98

113003-005AC
PSD-F1-253

PS Form 3800, April 1995

ATL GA 303 7 OC 20:08

Is your RETURN ADDRESS completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. Doug Neeley
Air, Radiation Tech. Branch
U S EPA - Region IV
61 Forsyth St.
Atlanta, GA 30303

4a. Article Number
Z 333 612 528

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

7. Date of Delivery
10-13-98

5. Received By: *(Print Name)*
Alan Lindsey

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 102595-97-B-0179 Domestic Return Receipt

Z 333 612 528

US Postal Service

Receipt for Certified Mail

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

Sent to Doug Neeley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta, GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 10-9-98 1130168-001-AC PSD-FI-253	

PS Form **3800**, April 1995

Z 333 612 525

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

Sent to James Shield	
Street & Number Santa Rosa Energy	
Post Office, State, & ZIP Code Northbrook IL	
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 1130168-001-AC P50-F1-253	10-9-98

PS Form **3800**, April 1995

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

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

Consult postmaster for fee.

3. Article Addressed to:
Mr. James Shield, VP
Santa Rosa Energy
650 Dundee Rd- Suite 150
Northbrook, IL 60062

4a. Article Number
Z 333 612 525

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

7. Date of Delivery
10/13/98

5. Received By: *(Print Name)*

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

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

PS Form **3811**, December 1994 102595-97-B-0179 Domestic Return Receipt

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

The Santa Rosa
PRESS GAZETTE
PUBLISHED WEEKLY
Milton, Santa Rosa County, Florida

STATE OF FLORIDA

County of Santa Rosa

Before the undersigned authority personally appeared
Susan Holley

who on oath says that he is Cashier
of the Press Gazette, a weekly newspaper published at Milton in Santa Rosa County, Florida; that the attached copy of advertisement being a Public Notice

in the matter of Intent to Issue Air Construction Permit

in the ______ court, was published in said newspaper in the issues of:

October 26 A.D., 1998
A.D., 19___
A.D., 19___
A.D., 19___
A.D., 19___
A.D., 19___

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

I (SWEAR) (AFFIRM) that the above information is true and correct to the best of my knowledge.

Susan Holley
(Signature of Applicant)

Sworn to and subscribed before me this
26 day of October 19 98

Carolyn V. Barnes
(Signature of Notary Public-State of Florida)

(Print, Type or Stamp Commissioned Name of Notary Public)

CAROLYN V. BARNES
MY COMMISSION # CC 402905
EXPIRES: November 12, 1998
Bonded Thru Notary Public Underwriters
NOTARY PUBLIC STATE OF FLORIDA

Personally known ✓ OR Produced Identification______
Type of Identification Produced: ______

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Santa Rosa Energy Center
Santa Rosa Energy LLC

Permit No. 1130168-001-AC (PSD-FL-253)
Pace, Santa Rosa County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Santa Rosa Energy LLC (SREL). The permit is to construct a natural gas-fired cogeneration facility consisting of: a nominal 167 megawatt (MW) combustion turbine-electrical generator; a supplementary-fired heat recovery steam generator capable of raising sufficient steam to generate another 74 MW from a steam turbine-electrical generator and to meet the process steam requirements of the adjacent Sterling Fibers facility; a 200 foot main stack; and ancillary equipment. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM10), nitrogen oxides (NOx), volatile organic compounds (VOC) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are Santa Rosa Energy LLC, 650 Dundee Road, Northbrook, Illinois 60062.

The cogeneration facility will be located within the boundaries of the existing Sterling Fiber chemical plant in Pace, Santa Rosa County. Nitrogen oxides emissions will be controlled by Dry Low NOx(DLN) gas turbine combustors and Low NOx duct burners capable of achieving overall emissions of 9.8 parts per million by volume at 15 percent oxygen (ppmvd@15%O2) with both the combustion turbine and duct burner operating simultaneously. Lower emission limits will apply if SREL choose selective catalytic reduction or selective non-catalytic reduction in lieu of or in conjunction with DLN technology. SO2 and PM/PM10 will be limited by use of natural gas. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum potential annual emissions in tons per year based on the original application are summarized below. NOx emissions will be lower as a result of the Department's BACT determination. Emission increases will also be lower because of decreased use by Sterling Fibers of existing and less efficient boilers.

Pollutants	**Maximum Potential Emissions**	**PSD Significant Emission Rate**
PM/PM10	55	25/15
SO2	7	40
NOx	402	40
VOC	45	40
CO	260	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. The effects of the project are considered to be minimal.

The department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

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

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

Department Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8300
Fax: 850/595-4417

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

102698
102698
1021980001

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Benjamin M.H. Borsch, P.E.
Santa Rosa Energy Center, LLC
2701 N. Rocky Point Dr.
Suite 1200
Tampa, FL 33607

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* R. Marzka

B. Date of Delivery 4-3-02

C. Signature

X R. Marzka

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. 7001 0320 0001 3692 9052

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7001 0320 0001 3692 9052

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To Benjamin M.H. Borsch, P.E.

Street, Apt. No.; or PO Box No. 2701 N. Rocky Pt. Dr., Ste. 1200

City, State, ZIP+4 Tampa FL 33607

PS Form 3800, January 2001 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. James Shield
SkyGen/Santa Rosa Energy LLC
650 Dundee Rd., Ste 350
Northbrook, IL 60062

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 2-26-01

C. Signature
X
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 3676

PS Form **3811**, July 1999 Domestic Return Receipt 102595-99-M-1789

7099 3400 0000 1449 3676

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:
Mr. James Shield

Postage	$	SantaRosa
Certified Fee		Postmark Here
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
Mr. James Shield
Street, Apt. No.; or PO Box No.
650 Dundee Rd., Ste 350
City, State, ZIP+4
Northbrook IL 60062

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. David Plauck
SkyGen/Santa Rosa Energy LLC
650 Dundee Road, Suite 350
Northbrook, IL 60062

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 2-26-0

C. Signature

X [signature]

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 3706

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1449 3706

Article Sent To:
Mr. David Plauck

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Santa Rosa Energy

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
David Plauck
Street, Apt. No.; or PO Box No.
650 Dundee Rd., Ste 350
City, State, ZIP+4
Northbrook, Il 60062

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Mr. David Plauck
Sky Gen / Santa Rosa Energy
650 Dundee Rd
Suite 350
Northbrook, IL
60062

2. Article Number *(Copy from service label)* Z 341 355 301

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6/2/00

C. Signature X J Bellandi ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Z 341 355 301

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

Sent to	David Plauck
Street & Number	Sky Gen / SANTA
Post Office, State, & ZIP Code	& ROSA En.
Postage	Northbrook, IL $
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	5-30-00 1130168-002-AC PSD-F1-253

PS Form **3800**, April 1995

SENDER: *COMPLETE THIS SECTION*	*COMPLETE THIS SECTION ON DELIVERY*
■ Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. ■ Print your name and address on the reverse so that we can return the card to you. ■ Attach this card to the back of the mailpiece, or on the front if space permits.	A. Received by *(Please Print Clearly)* B. Date of Delivery 6/2/00 C. Signature X J Bellandi ☐ Agent ☐ Addressee D. Is delivery address different from item 1? ☐ Yes If YES, enter delivery address below: ☐ No
1. Article Addressed to: Mr. James Shield Santa Rosa Energy 650 Dundee Rd, Suite 150 Northbrook, IL 60062	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* Z 341 355 300

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Z 341 355 300

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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

Sent to James Shield	
Street & Number Sky Gen/Santa	
Post Office, State, & ZIP Code Rosa En.	
Postage North	$ brook, IL
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 5-30-00 1130168-002-AC PSD-F1-253	

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
James Shield, VP
Santa Rosa Energy
650 Dundee Rd - Suite 150
Northbrook, IL
60062

4a. Article Number
Z 333 612 566

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

7. Date of Delivery
12-7-98

5. Received By: (*Print Name*)

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

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

PS Form **3811,** December 1994 102595-97-B-0179 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 612 566

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

Sent to James Shield	
Street & Number Santa Rosa	
Post Office, State, & ZIP Code Northbrook, IL	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 12-4-98 1130168-001-AC P50-F1-253	

PS Form **3800**, April 1995