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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.

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

RECEIVED

DEC 08 1998

NORTHWEST FLORIDA
DEP

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.

[Signature]
(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. Section I - Facility Description: *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. Section II - Administrative Requirements, Specific Condition 9: *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.]

- 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

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

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

- 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.

- 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.

- 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 SO₂ 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.

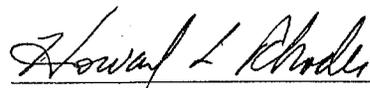
STATEMENT OF BASIS:

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
Appendix GC

BACT Determination
Construction Permit General Conditions


Howard L. Rhodes, Director
Division of Air Resources
Management

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

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.

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

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 (SO₂) or volatile organic compounds (VOC), 25/15 TPY of particulate matter (PM/PM₁₀), 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.

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

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 Blainstone 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)]

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

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.

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

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

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 1,780 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 $3,280 \times 10^6$ 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)]

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

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 % O₂. 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

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

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% O₂ (24-hr block average), and with the combustion turbine operating and the duct burner off shall not exceed 9 ppmvd at 15% O₂ (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% O₂ 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 (SO₂) Emissions: SO₂ 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 SO₂ 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.]

AIR CONSTRUCTION PERMIT PSD-FL-253 (1130168-001-AC)

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

25. Particulate Matter emissions : PM/PM₁₀ 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/PM₁₀ emissions. [40CFR60 Subpart Da and 62-4.070 F.A.C.]
26. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM₁₀ 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.

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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 SO₂ and PM/PM₁₀ emission limits: Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO₂ and PM₁₀. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO₂ 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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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.

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SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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 SO₂ emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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).

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 PM₁₀), 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 SO₂, and 55 TPY of PM/PM₁₀.

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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% O₂. (assuming 25 percent efficiency) and 150 ppm SO₂ @15% O₂ (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.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 MS7001FA 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 501FC CTs Canceled GE CTs
Tallahassee, FL	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231FA 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 501F 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 CON = Continuous DLN = Dry Low NO_x Combustion GE = General Electric
 DB = Duct Burner HSCR = Hot SCR SCR = Selective Catalytic Reduction WH = Westinghouse
 NG = Natural Gas FO = Fuel Oil LPG = Liquefied Propane Gas ABB = Asea Brown Bovari
 CT = Combustion Turbine ISO = 59°F WI = Water or Steam Injection 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

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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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BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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% O₂). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O₂.

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 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.

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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 caused 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 NO₂, 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.

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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 Navy Yard 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.

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Particulate Matter (PM/PM₁₀) 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 (PM₁₀).

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 PM₁₀ 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/PM₁₀ 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/PM₁₀. 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 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 than 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

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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 SERL 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% O₂. 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

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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 slightly 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, SO₂, VOC (ozone) or PM₁₀.
- 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

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the total capital cost of the project by \$1,462,846, with an annualized cost of \$548,257 per year. SREL estimated leveled 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 burner on, the levels are still relatively low except at very high operating rates.
- BACT for PM₁₀ 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.
- PM₁₀ 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 include 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

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DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

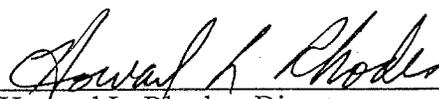
A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

Approved By:

 P.E.

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



Howard L. Rhodes, Director
Division of Air Resources Management

12/2/98
Date:

12-4-98
Date:

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.

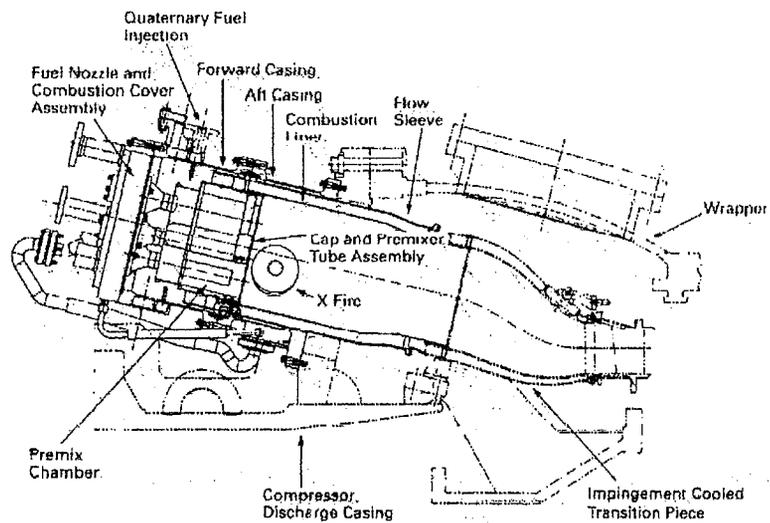
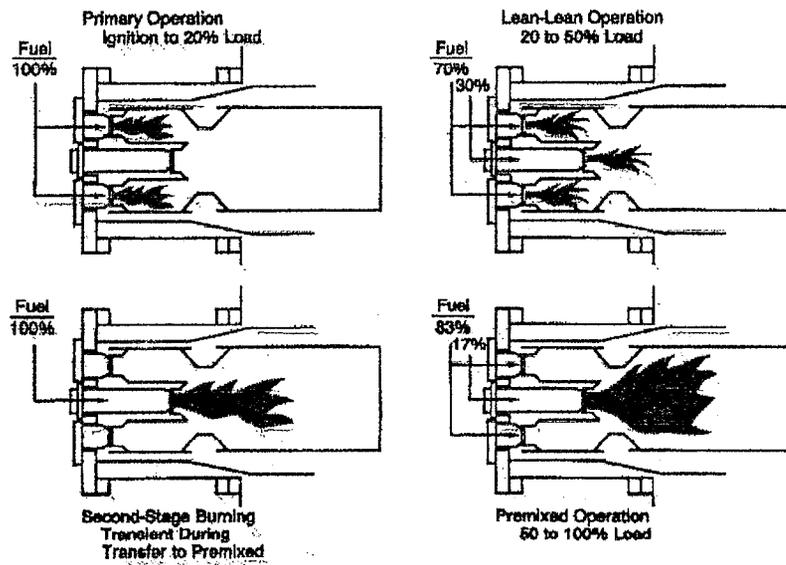


Figure 1 - Dry Low NOX Operating Modes - DLN-1

Cross Section of DLN-2.0

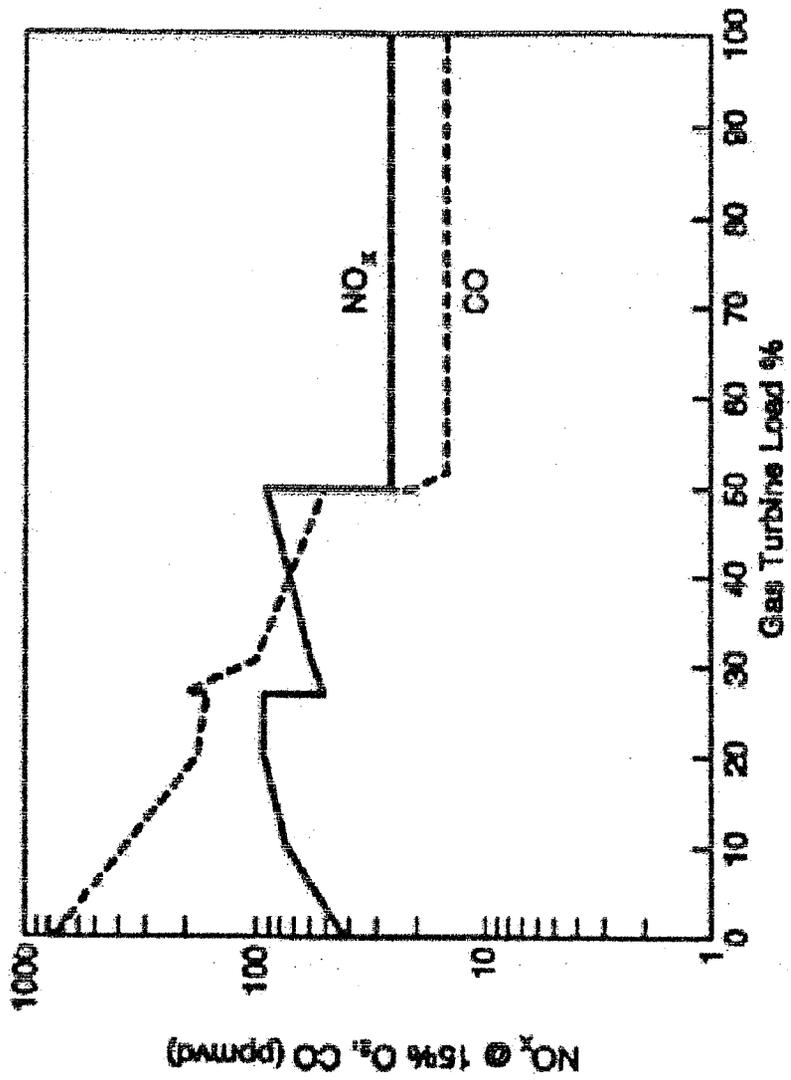


Figure 2 - Emissions Performance Curves for GE DLN-2 Combustors
 Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

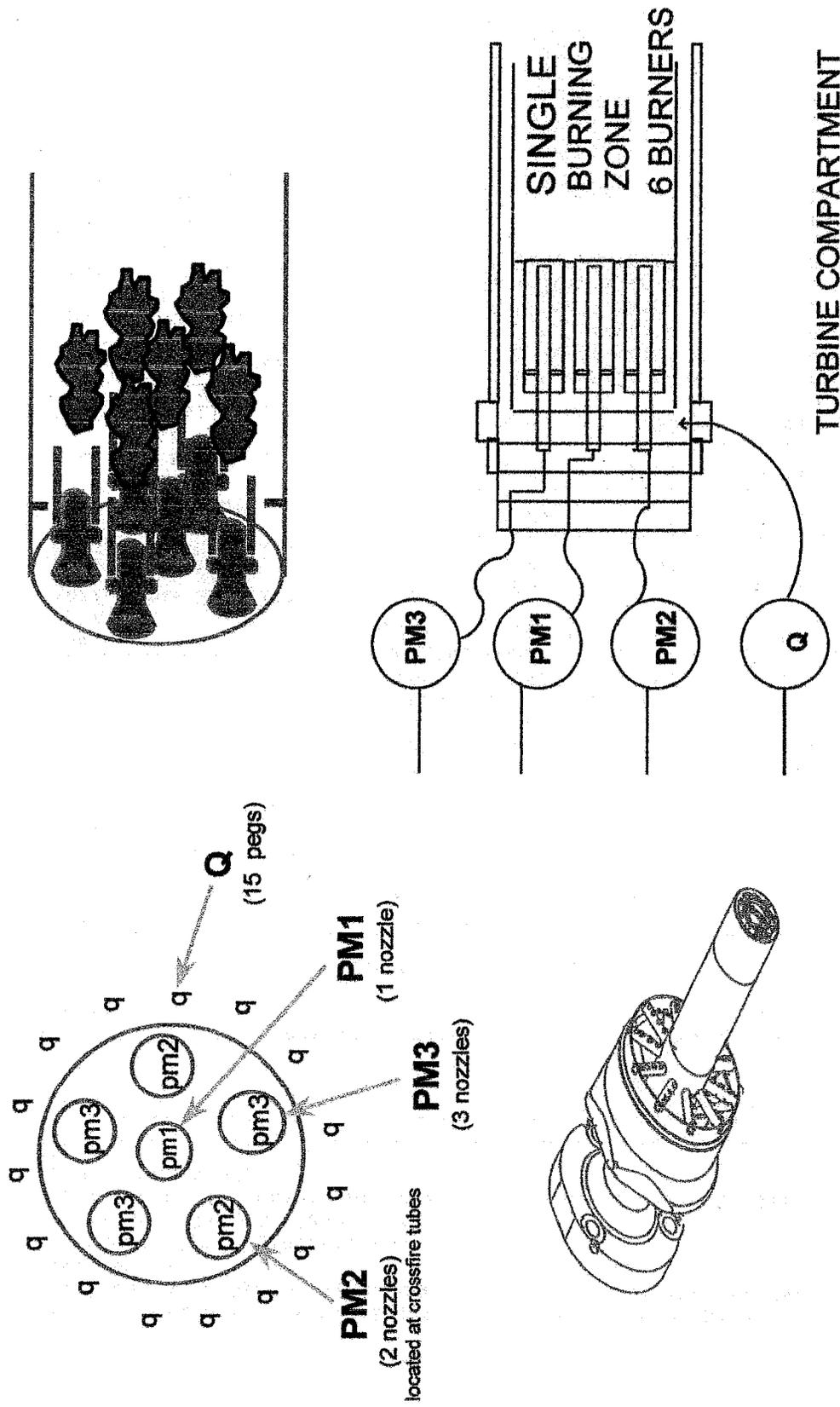


Figure 3 - GE DLN-2.6 Combustor and Nozzle Arrangement

Gas Turbine - Hot Gas Path Parts

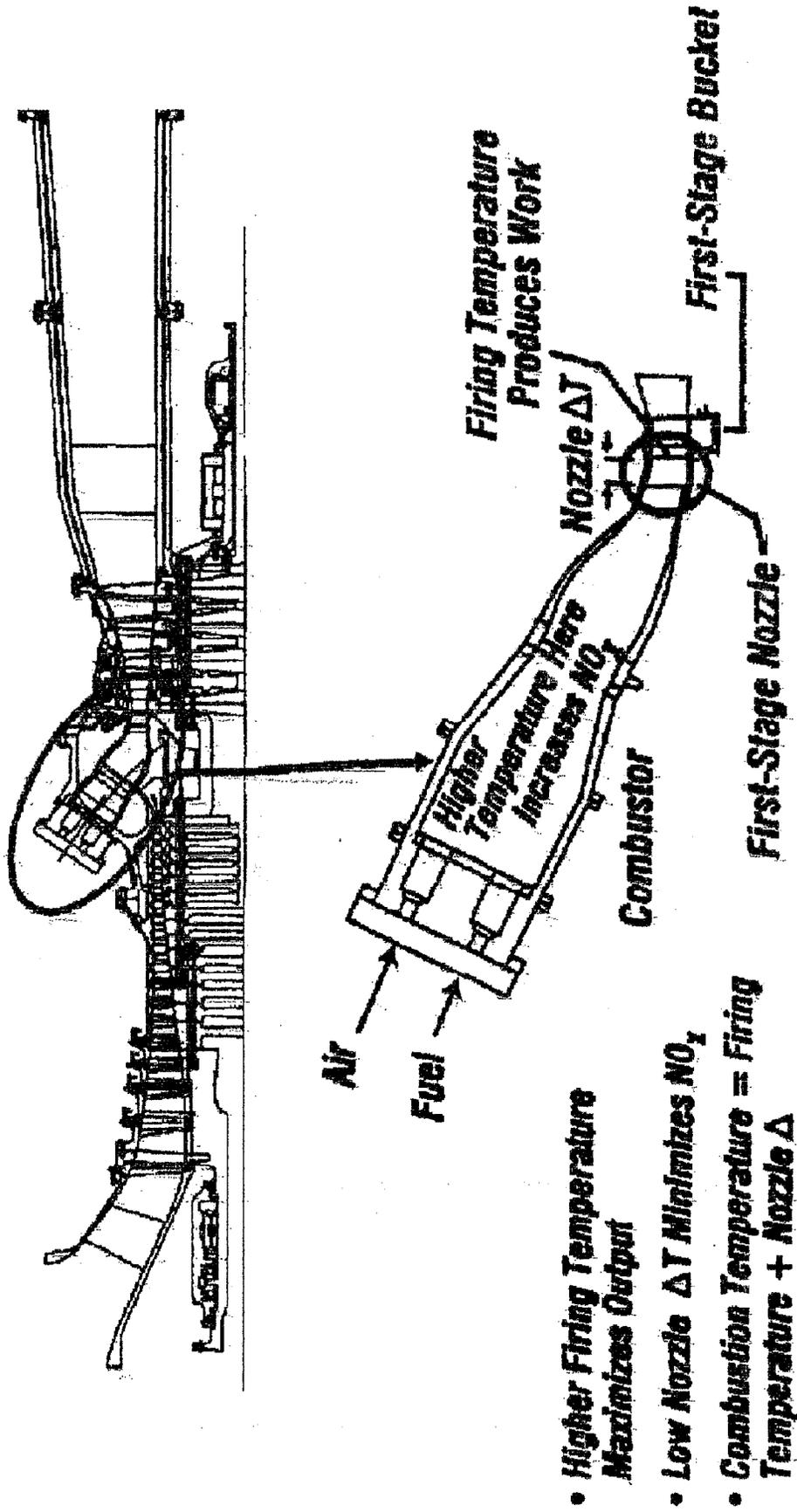
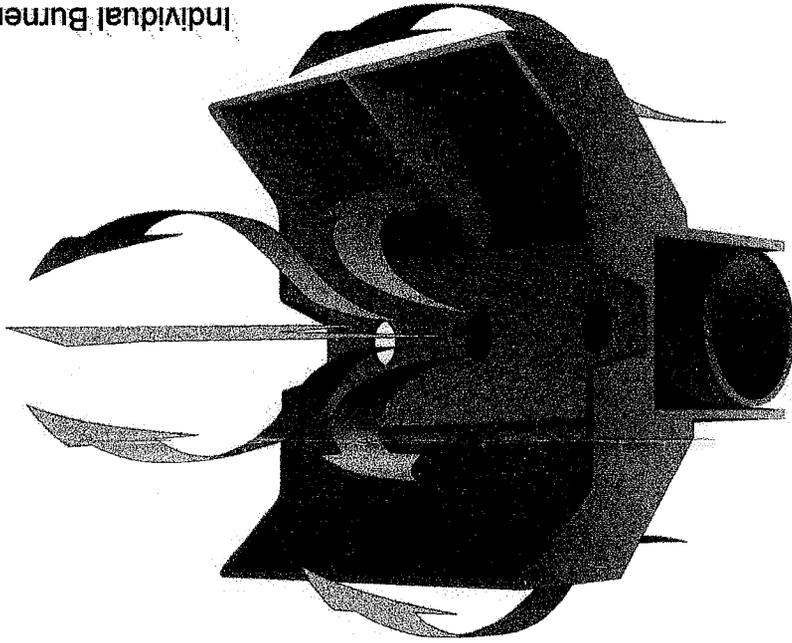


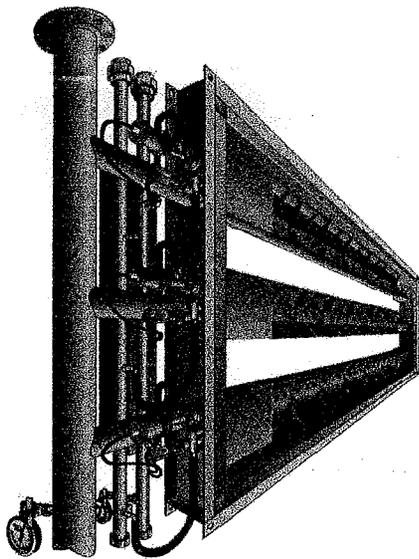
Figure 4 - Relation Between Flame Temperature and Firing Temperature

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

Individual Burner



Burner Arrangement



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

- G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
- G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
- G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey 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.

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

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 extent 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.