Department of Environmental Protection

FLORIDA

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 15, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

Re: DEP File No. 1110099-002-AC (PSD-FL-304)
Midway Energy Center
Three Simple Cycle Combustion Turbines

Dear Mr. Jacoby:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Midway Energy Center to be located near Port St. Lucie and Fort Pierce in St. Lucie 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 must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. 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 other 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 or contact him at 850/921-9523.

Sincerely,

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

CHF/al

Enclosures

"More Protection, Less Process"

Printed on recycled paper.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631
________________________________/

DEP File No. 1110099-002-AC (PSD-305)
Midway Energy Center, Units 1 – 3
St. Lucie County

Enclosed is the Final Permit Number PSD-FL-305 to construct three 170-megawatt dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located in St. Lucie 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.

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 2/14/01 to the person(s) listed:

Ben Jacoby, MDC*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Chair, St. Lucie County BCC
Blair Burgess, P.E., ENSR

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 2/14/01
(Clerk) (Date)

FINAL DETERMINATION
File No. 1110099-002-AC (PSD-FL-305)
MIDWAY DEVELOPMENT COMPANY, L.L.C.
510 MW SIMPLE CYCLE FACILITY

The Department distributed a Public Notice package on December 18, 2000 for the project to construct a nominal 510-megawatt (MW) natural gas and fuel oil-fired simple cycle facility to be known as the Midway Energy Center near Port St. Lucie and Fort Pierce in St. Lucie County. The project consists of three nominal 170 MW General Electric 7FA combustion turbine-electrical generators, three 150-foot stacks, a 2.5 million gallon fuel oil storage tank, a 0.6 million gallon fuel oil "day" tank, and other ancillary equipment.

The Public Notice of Intent to Issue was published on December 21, 2000 in The Tribune. Written comments were received from EPA Region IV and the applicant, Midway Development Company, L.L.C (Midway - an affiliate of Enron North America).

The written comments (in italics) are addressed below. Each is followed by the Department's response.

EPA Comments

1. *Section III. Emission Units Specific Conditions, Applicable Standards and Regulations, 6.: 40 C.F.R. Subpart Dc is an applicable requirement for the gas heater. In 40 C.F.R. § 60.41c, a steam generating unit is defined as a device that combusts any fuel and produces steam or heat water or any other heats transfer medium. Heat transfer medium is defined as any material that is used to transfer heat from one point to another point. The natural gas heaters meet the definition of steam generating unit; therefore, they are an affected facility as defined in 40 C.F.R. § 60.40c(a). Also, pursuant to 40 C.F.R. § 60.48c(g), the permittee must record the amount of each fuel combusted each day. Please include this applicable requirement in the permit.*

   The Department agrees with EPA and the requirements of 40 CFR Subpart Dc will be included for the heaters.

2. *Section III. Emission Units Specific Conditions, General Operation Requirements, 13. Maximum allowable hours: To limit the potential to emit, the operation limitations (hours of operation per year) should be expressed in terms of 12 consecutive months, rather than calendar year. This 12-month consecutive limit prevents the enforcing agency from having to wait for long periods of time to establish a continuing violation before initiating enforcement.*

   The Department agrees with EPA and the hours per year will be changed to read 12 consecutive months.

3. *Section III. Emission Units Specific Conditions, Excess Emissions. 25. The Florida Department of Environmental Protection should include definitions of what constitutes "startup" and "shutdown" as referenced in this section.*

The Department does not allow extended operation at low loads, during which such emissions typically occur. The facility must also employ good operating practices to allow excess emissions.

At the same time, the Department is aware that emissions are less from the GE 7FA units at low loads (< 50 percent of full load) than previously believed. This is based on reports from new installations including JEA.

The Department will progressively implement EPA's comments for future projects as we get emissions data from facilities required to demonstrate compliance by CEMS. As drafted, the permit includes Specific Conditions (22, 23, 24, 44, 45) related to excess emissions during startup, shutdown, and valid, documented malfunctions. See condition 43 of Section III of this permit for provisions that relate to excluding periods of CEM system data recorded for NO_X and CO for episodes of startup, shutdown and malfunction. However, these periods are recorded and reported as excess emissions as stated in conditions 24 and 45.

Gas turbine startup is the commencement of operation of a gas turbine which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion.

Midway's comments:

4. *Section II. Administrative Requirements, Specific Condition (SC) 8 (page 5 of 15): At our request, the permit expiration date was extended. However, we believe it was the Department's intent to revise the language as follows: "The expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2002~~3~~."*

   The typographical error was corrected to read 2002.

5. *Section III. General Operation Requirements, SC 13 and 14 (pages 7 and 8 of 15): As suggested in a separate letter to the Department, dated January 23, 2001, it's requested that the language in SC 13 and 14 be revised. The suggested language below provides the Department with reasonable assurance that the intent is for natural gas to be the primary fuel for this proposed project:*

   Specific Condition 13 - Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any calendar year, as may be adjusted in condition 14 below, based on oil fired run hours. ~~The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any calendar year~~. No single combustion turbine shall operate more than 5,000 hours in a single year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

   Specific Condition 14 - Fuel oil usage: ~~The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period. The Department may waive this requirement during the first 24 months of operation based on natural gas availability.~~

In order to encourage the maximum use of natural gas as fuel, during any calendar year the three stationary gas turbines shall operate on fuel oil for no more than an average of 1000 hours per installed unit. Furthermore, during any calendar year, the maximum allowable operating hours referenced in condition 13 above shall be reduced by two hours for each oil fired hour in excess of an average of 500 per installed unit. For example, if the three stationary gas turbines operate on fuel oil in any calendar year for an average of 550 hours per installed unit, the total maximum allowable operating hours shall be decreased to 3,400.

[Rule 62-212.400, F.A.C. (BACT)]

Note: In a phone conversation with Midway representatives on February 8, the company further proposed to reduce to 250 hours the level at which the "2 for 1" trigger would kick in. Therefore if the three stationary gas turbines operate on fuel oil in any calendar year for the permitted average of 1000 hours per installed unit, the total maximum allowable operating hours shall be decreased to 2,000 hours.

The Department met with Midway representatives on January 17 to discuss these matters. The Department emphasized that a major part of the Best Available Control Technology (BACT) is the use of natural gas. The company argued that there is not yet enough firm supply of natural gas to insure that in a given year or in a given 12-month period they can commit to firing more gas than fuel oil.

Apparently Florida Gas Transmission (FGT) Phase IV and V (and proposed Phase VI) Expansions extend to points North and West of the planned Midway site. Therefore Midway will rely on interruptible supply from the existing FGT capacity in Southeast Florida if it chooses to purchase gas from FGT. This situation could change as FGT considers possible future capacity expansion in Southeast Florida.

The approved Gulfstream Pipeline will extend from Manatee County and includes segments to St. Lucie and Belle Glade. This presents another opportunity for Midway to obtain gas. Additionally, Enron (parent of Midway) has announced a possible project involving construction of a liquefied natural gas (LNG) handling terminal in the Bahamas together with a pipeline to the Southeast Florida Coast.

If the company actually uses more fuel oil than gas, then a better effort needs to be made to reduce emissions while firing fuel oil. For example, nitrogen oxides (NO_X) emissions while firing fuel oil are 42 parts per million by volume dry (ppmvd), whereas emissions while firing natural gas are only 9 ppmvd.

Midway and other companies argue that the NO_X guarantee while burning fuel oil is still 42 ppmvd from General Electric. They are not willing to commit to further wet injection to reduce emissions to less than the guaranteed values. However, it is clear that lower emissions are feasible with wet injection than indicated by the guarantees. For example, initial compliance tests on a GE 7FA simple cycle combustion turbine at the JEA Kennedy Plant indicated NO_X emissions of 30 ppmvd @15% O_2. The added costs in terms of reduced lifetime and increased maintenance are unknown.

There is already a requirement (within Section III. Condition 19) for Midway to develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised.

The Department concludes that Midway's proposed draft permit revision, the fuel oil use hammers, and the various gas supply options will encourage Enron to make sure more gas becomes available for its planned Midway Project as well as for its other projects planned in Broward County. The permit will be modified accordingly.

It is noted that Midway's potential to emit will be significantly reduced because maximum oil use will reduce total hours of operation by an average of 1500 per unit. For example, potential NO_X emissions from the facility will be reduced from roughly 735 tons per year to approximately 600 tons per year.

6. *<u>Section III. SC 17 (page 8 of 15):</u> The permit language states that "The permittee shall provide manufacturer's emissions vs. load diagrams for the DLN and wet injection systems prior to their installation." Past requests of the manufacturer for these types of diagrams have been unsuccessful. Typically, the manufacturer will provide emission estimates at various load points corresponding to various inlet temperature cases. These emission values, that are the basis for this permit, were previously provided in the permit application. It's requested that the word "diagrams" in the above sentence be replaced with the word "estimates".*

   The Department has regularly obtained such diagrams from operators throughout the State. The Department will to change the language from "prior to installation" to "upon installation and completion of testing" for submittal of the required diagrams.

7. *<u>Section III. SC 19 (page 9 of 15):</u> The language concerning fuel oil firing should be revised as follows: "In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd at 15% O_2 to be demonstrated by <u>initial</u> stack test."*

   The Department revised this condition to include the word initial as suggested. Reference to Method 20 will be added for consistency with the previous condition.

8. *<u>Section III. SC 20 (page 9 of 15):</u> The CO emission limit for fuel oil presented in the permit application was based on 20 ppmvd. At a temperature of 30 °F, this corresponds to 69.6 lb/hour, not 46 lb/hour, as shown in the draft permit. The 20 ppm concentration is based on 100% load. Concentrations of CO are estimated to be as high as 22 ppm at 75% load factor and 30 ppm at 50% load factor. The peak emission estimate is 78.3 lb/hour at 50% load and 91°F. Based on these factors we request that the permit limit for oil firing be expressed as follows: "The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 31 lb/hr (gas) and neither 20 ppmvd nor 70 lb/hour (fuel oil) to be demonstrated by stack tests at full load operation."*

   This condition will be revised as suggested. The Department notes, however, that initial testing of General Electric 7FA combustion turbines indicates emissions in the range of 0.5 to 2 ppm whether burning natural gas or fuel oil. Such results have been observed at TECO Polk Power, JEA and City of Tallahassee facilities.

The Department will monitor long-term performance on CO at some of the combined cycle units that have continuous emissions monitors. This may result in lower emission limits issued to applicants for combustion turbine projects in the future.

9. *Section III. SC 27 (page 10 of 15): The last sentence should be revised as follows: "...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. ~~18 and~~ 19."*

   This condition was revised to read 19.

10. *Section III. SC 29 (page 11 of 15): The permit language indicates that emission testing by EPA Reference Methods 9 and 10 (for visible emissions and CO emissions, respectively) are to be conducted both initially and annually for both fuels. In the past, the Department has issued permits (e.g., Hines Energy Complex) with language that requires that annual testing be done on fuel oil (the backup fuel) only if a threshold number of operating hours on oil is exceeded (e.g., 400 hr/CT) during a rolling 12-month period. This is because it's a financial hardship to require operation on the more expensive fuel. It's requested that the conditions be revised to include annual testing for VE and CO emissions on oil, only if a CT exceeds 400 hours of operation in a 12-month rolling period.*

    The Department does not consider it to be a financial hardship for Midway to test for CO and VE while firing fuel oil and it is not clear that fuel oil is exclusively just the back-up fuel. In the case of Hines, the allowable hours on fuel oil operation are much lower than the hours on natural gas operation. At Midway, the fuel oil firing can be very significant compared with natural gas. Additionally, permitted CO emissions are much higher than for the fuel oil case than for the natural gas case.

11. *Section III. SC 33 (page 11 of 15): It's requested that the same language be included here regarding the annual testing requirement for visible emissions while firing oil.*

    See discussion in 10 above.

12. *Section III. SC 36 (page 12 of 15): The second sentence should be revised as follows: "...corrected for the average inlet ~~ambient~~ air temperature during the test...".*

    The Department will revise this condition as suggested.

13. *Section III. SC 45 (page 13 of 15): The last sentence states that "these excess emissions periods shall be reported as required in Specific Conditions 24 and 46." The reference to SC 24 appears to be incorrect, as it refers to the limitation for visible emissions.*

    The reference to Specific Condition 24 in Specific Condition 45 will be revised to read Specific Condition 27.

14. *Section III. SC 46 (page 14 of 15): Although the language is intended to instruct on the procedure to determine compliance with the 24-hour rolling average, the second sentence refers to a separate compliance determination being conducted at the "end of each operating day". This language is appropriate in the context of a 24-hour*

block average, but should be deleted from SC 46, which is addressing rolling averages.

This condition was revised to read 24-hour block average.

15. <u>Section III. SC 47 (page 14 of 15):</u> *The Specific Conditions referenced in the last sentence of this condition (20, 21 and 29) all appear to be incorrect. The conditions need to be cross-referenced correctly or deleted. Also, the appropriate DEP office to notify would be the Southeast District, not the South District.*

    This condition was revised to read reference to Specific Conditions 18, 19 and 24. The District office was changed as suggested.

16. <u>Section III. SC 49 (page 14 of 15):</u> *Some of the text appears to be missing. There doesn't appear to be any schedule for testing of sulfur or nitrogen in natural gas in the bulleted items. In fact, the bulleted items appear to be related to compliance with the Acid Rain requirements of Parts 72 and 75, not with Part 60 Subpart GG compliance (which is what requires a Custom Fuel Schedule).*

17. <u>Section III. SC 50 (page 15 of 15):</u> *It's requested that the requirement to conduct sampling and analysis for fuel bound nitrogen content be deleted. Typically, the requirement to monitor water-to-fuel ratio, combined with the requirement to analyze for fuel bound nitrogen content, provides a surrogate for NO_X compliance. As recognized by the Department in the language of SC 48, the NO_X CEMS are to be used in lieu of the water/fuel monitoring system for reporting excess emissions. Given that NO_X CEMS will be used for compliance, the monitoring of the fuel bound nitrogen content serves no useful purpose, and should not be required.*

    The Department replaced the above conditions with the new condition (SC 49) below. The requirements of the 40CFR60, Subpart GG will be attached as Appendix GG. This new Appendix includes all the Department requirements regarding this Subpart GG.

New Specific Condition 49:

<u>Fuel Sulfur Records</u>: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

Compliance with the fuel sulfur limit for *natural gas* shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

Compliance with the *fuel oil* sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

18. *Particulate Limits: The Department has determined that measurement of front-half catch by EPA Method 5 is sufficient to demonstrate the BACT emission limit for* PM_{10}.

EPA Method 5 measuring the front-half catch only is now specified for compliance with the PM_{10} standard. Because the back-half catch is excluded, the emission limits are reduced from 18 to 10 and from 34 to 17 pounds per hour while firing natural gas and fuel oil respectively. These values are equal to previous BACT determination for GE 7FA simple cycle units.

CONCLUSION

The Department will issue the permit with the changes noted above.

Jeb Bush
Governor

Department of
Environmental Protection

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

David B. Struhs
Secretary

PERMITTEE:

Midway Development Company
1400 Smith Street
Houston, Texas 77002-7631

Permit No.	PSD-FL-305
File No.	1110099-002-AC
SIC No.	4911
Expires:	June 30, 2003

Authorized Representative:

Ben Jacoby

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers; one 2.5-million gallon fuel oil storage tank; one 0.6 million gallon fuel oil storage tank; a natural gas heater; and three 80-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located Northwest of the intersection of I-95 and W. Midway Road near Port St. Lucie and Ft. Pierce in unincorporated St. Lucie County. UTM coordinates are Zone 17; 556.7 km E; 3028.5 km N.

STATEMENT OF BASIS:

This Air 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 and Tables made a part of this permit:

Appendix GG	40 CFR 60 NSPS, Subpart GG
Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 12/21/00 Notice of Intent published in The Tribune, St Lucie County
- 12/18/00 Distributed Intent to Issue Permit
- 11/09/00 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 on November 9, 2000
- Letters from Enron North America dated December 5, 2000; January 23, and February 2, 2001.
- Letter from U.S. EPA Region IV dated January 19, 2001
- Department's Intent to Issue and Public Notice Package dated December 15, 2000
- Updated application received from Enron North America on January 17, 2001
- 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 *Permitting Authority*: Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the *Compliance Authority*: DEP Southeast District office, 400 North Congress Avenue W, West Palm, Florida, 33401 and phone number 561/681-6755, fax 561-681-6755. Copies shall be sent to the DEP Port St. Lucie Branch office, 1801 SE Hillsmoore Dr, C 204, Port St. Lucie, Florida 34952 and phone number 561/398-2806, fax 561/398-2815.

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. PSD Approval to Construct Expiration: 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. BACT Determination Revision: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will

also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

8. Completion of Construction: The permit expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2002. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

9. Permit Expiration Date Extension: 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.]

10. 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's Southeast District office. [Chapter 62-213, F.A.C.]

11. 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.]

12. 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 Southeast District and a copy to the DEP's Port St. Lucie Branch offices by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

13. Quarterly Reports: Semiannual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (2000 version), shall be submitted to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

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. 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.]

2. 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

3. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines 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). [Rule 62-204.800(7)(b), F.A.C.]

4. ARMS Emission Unit 004, Fuel Storage, consisting of one 2.5 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 005, Fuel Storage, consisting of one 0.6 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. ARMS Emission Unit 006, Fuel Heating, consisting of one 13 million Btu per hour natural gas heater to heat natural gas used by the combustion turbines. This unit shall comply with applicable requirements of 40CFR60, Subpart Dc.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
{Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 30 °F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,700 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,900 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. 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)]

9. 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.
[Rule 62-296.320(4)(c), F.A.C.]

10. 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 Southeast District 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.]

11. 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.]

12. 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.]

13. Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any consecutive 12-month period. This

amount shall be reduced by two hours for each fuel oil-fired hour in excess of an average of 250 per installed unit. No single combustion turbine shall operate more than 5,000 hours in any consecutive 12-month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any consecutive 12-month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems upon completion of initial testing. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology.

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	11/17 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC (not PSD)	As Above	2.8 ppmvd @15% O_2 (Gas or Fuel Oil)
CO	As Above	9 ppmvd @15% O_2 (Gas) 20 ppmvd @15% O_2 (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	9 ppmvd @15% O_2 (Gas) 42 ppmvd @15% O_2 (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:
    - *While firing Natural Gas*: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppmvd @15% O_2 on a 24-hr block average as measured by the continuous emission monitoring system (CEMS) in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 62 pounds per hour nor 9 ppmvd @15% O_2 to be demonstrated by the initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
    - *While firing Fuel Oil*: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd @15% O_2 on the basis of a 3-hr block average as measured by the CEMS in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd @15% O_2 to be demonstrated by initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
    - *NO_X Reduction Plan*: The permittee shall develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without adversely affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [Rule 62-212.400, F.A.C., BACT Determination].
20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 9 ppmvd @15% O_2 nor 31 lb/hr (gas) and neither 20 ppmvd @15% O_2 nor 70 lb/hr (fuel oil) at 30^{0}F to be demonstrated by stack tests. [Rule 62-212.400, F.A.C.]
21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas shall exceed neither 2.8 ppmvd @15% O_2 nor 6 lb/hr (gas or fuel oil) to be demonstrated by initial stack tests. [Non-applicability of Rule 62-212.400, F.A.C.]
22. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions: SO_2 and SAM emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or No. 2 distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year per unit. Emissions of SO_2 shall exceed neither 11 lb/hr (natural gas) nor 104 lb/hr (fuel oil). Emissions of sulfuric acid mist shall exceed neither 2 lb/hr (natural gas) nor 16 lb/hr (fuel oil). These emissions shall be measured by applicable compliance methods described below.
    [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]
23. Particulate Matter (PM/PM_{10}): PM/PM_{10} emissions shall exceed neither 10 lb/hr (gas) nor 17 lb/hr (fuel oil) to be demonstrated by initial stack tests. [Rule 62-212.400, F.A.C.]

24. Visible Emissions: Visible Emissions shall not exceed 10 percent opacity to be demonstrated by visual observation tests.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. 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 for other reasons unless specifically authorized by DEP for longer duration.

26. 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.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southeast District 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. Following the NSPS format, 40 CFR 60.7 Subpart A, 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. 19.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (2000 version)].

COMPLIANCE DETERMINATION

28. Compliance Test Schedules: 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 and as required by the *Compliance Authority*. [Rules 62-204.800 and 62-4.070(3) F.A.C.]

    - *Initial*: Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. 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 such as change or tuning of combustors.
    - *Annual*: 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 each unit as indicated.
    - *Prior Permit Renewal*: All tests shall be conducted within 12 months prior permit renewal.

29. Reference Methods: The following reference methods as described in 40 CFR 60, Appendix A (2000 version), and adopted by reference in Chapter 62-204.800, F.A.C. shall be used to demonstrate compliance with the allowable emissions limits. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5, "Determination of Particulate Matter Emissions from Stationary Sources" (I).
    - 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 NO_X compliance with 40CFR60 Subpart GG.
    - EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements.
    - EPA Reference Method 25A, "Determination of Total Hydrocarbon Concentrations." Correction for methane by EPA Method 18 is allowed. Initial test only.
30. Compliance with CO emission limits: 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
31. Compliance with the VOC emission limits: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.
32. Compliance with the NOx emission limits: Compliance with the NO_X emissions limits shall be determined by stack tests and a CEMS as specified in specific conditions 30, 45 and 46.
33. Compliance with the PM/PM_{10} and VE emission limits: Initial and annual tests are required for visible emissions (VE). Initial stack test is required for PM/PM_{10}. Tests for PM and VE shall be conducted concurrently.
34. Continuous compliance with the PM/PM_{10}, SO_2 and sulfuric acid mist emission limits: Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the restricted use of No. 2 distillate fuel oil (or superior grade) are the methods for determining continuous compliance for PM/PM_{10}, SO_2 and sulfuric acid mist.
35. Test Method for Natural Gas and Fuel Oil Sulfur Content: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM D 2880-71 (or equivalent) for sulfur

content of *liquid fuel* and 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 schedules. 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. Refer to Appendix GG.

36. Testing procedures: Initial testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average inlet 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 compressor inlet temperature) and 110 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. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

38. Test Notification: The DEP's Southeast District and the DEP's Port St. Lucie Branch District offices 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).

39. 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.

40. Test Results: Compliance test results indicating the results of the required compliance tests shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie Branch District offices no later than 45 days after completion of the last test run. 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.

NOTIFICATION, REPORTING, AND RECORDKEEPING

41. Records and Reports: All measurements, records, and other data required to be maintained by MDCLLC 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.

42. Notifications: All notifications and reports required by 40 CFR60, Subpart A shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie Branch District offices.

MONITORING REQUIREMENTS

43. Continuous Monitoring System Procedures: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the NO_X emissions from each CT. Each device shall properly function prior to the initial performance tests and comply with the applicable monitoring system requirements of 40 CFR 75.62. Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 62-4.130, F.A.C and 40CFR75]

44. Continuous Monitoring Certification and Quality Assurance Requirements: 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. Continuous Monitoring System Operation: The continuous monitoring systems (CEMS) for NO_X shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Valid hourly emission rates shall not include periods of startup, shutdown, fuel switching, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as require in Specific Conditions 27 and 46.
[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700. 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 60.13, 40 CFR 75].

46. 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 a 24-hour block average (gas) and 3-hr block average (oil). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of 24-hr (gas) and 3-hr (oil) valid hourly

measurements from the previous operating hours. A valid hourly emission rate shall be calculated for each hour (during which fuel is fired) in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by Rule 62-210.700, F.A.C.
[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

47. CEMS for Reporting Excess Emissions: The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (2000 version). Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15 % oxygen) are above the permit limits listed in Specific Conditions 18 and 19 shall be reported to the DEP Southeast District office as required in Specific Condition 24.

48. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (2000 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (2000 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

49. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

50. 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]

Midway Energy Center
PSD-FL-305 and 1110099-002-AC
St. Lucie County, Florida

BACKGROUND

The applicant, Midway development Company, L.L.C. (Midway, an affiliate of Enron North America) proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Midway Energy Center, East of Arcadia in unincorporated St. Lucie County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 80-foot stacks. Midway proposes to operate these units up to 3,500 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated December 15, 2000, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on November 9, 2000 (revised December 5) and included a proposed BACT proposal prepared by the applicant's consultant, ENSR.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	9 ppmvd @ 15% O_2 (gas)[1] 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	9 ppmvd (gas, baseload) 30 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, 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). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Midway is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the Midway Energy Center.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple cycle turbines. Two (Carson and McClellan) were permitted in ozone non-attainment areas and two (Lakeland and PREPA) were permitted as continuous duty projects. The proposed Midway Energy Center is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 11/00. 1000 hrs on oil
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 10/00. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 2/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Tenaska Heard, GA	960	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
RockGen Cristiana, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some 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 Formation

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 near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

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, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 1 which is from a General Electric discussion on these principles.

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Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Midway project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 1000 hours per year (per CT).

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the Midway Project. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

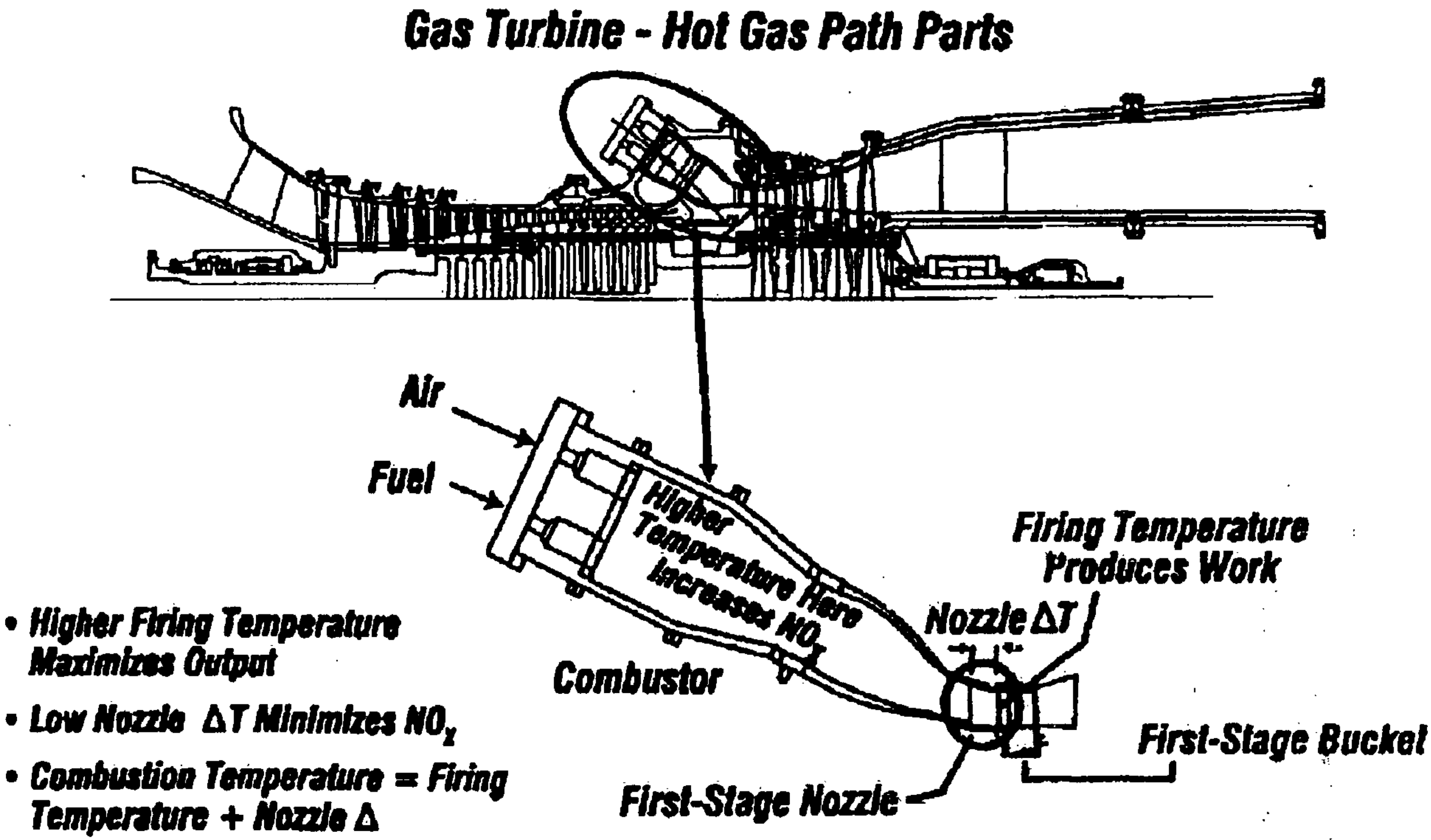

Figure 1 – Relation Between Flame Temperature and Firing Temperature

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 incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X.

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Tests at the JEA[2] Kennedy Plant indicated that 30 ppmvd is achievable on a short-term basis.

Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[3] where water is scarce, but the Department has no information on the results. Mitsubishi (who also make a 501F) is developing a dual-fuel premixed DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[4] The details are not available in English.

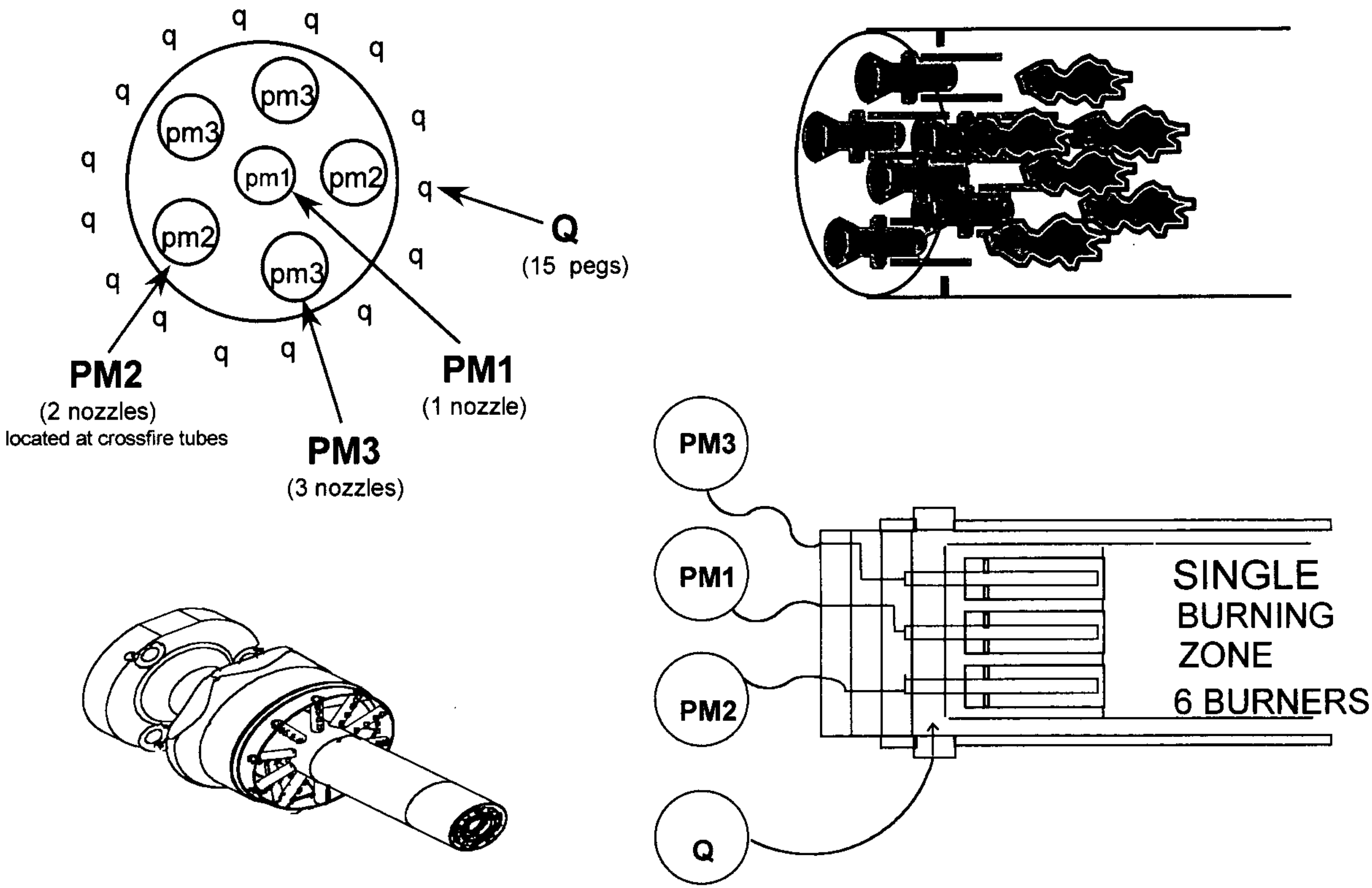

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

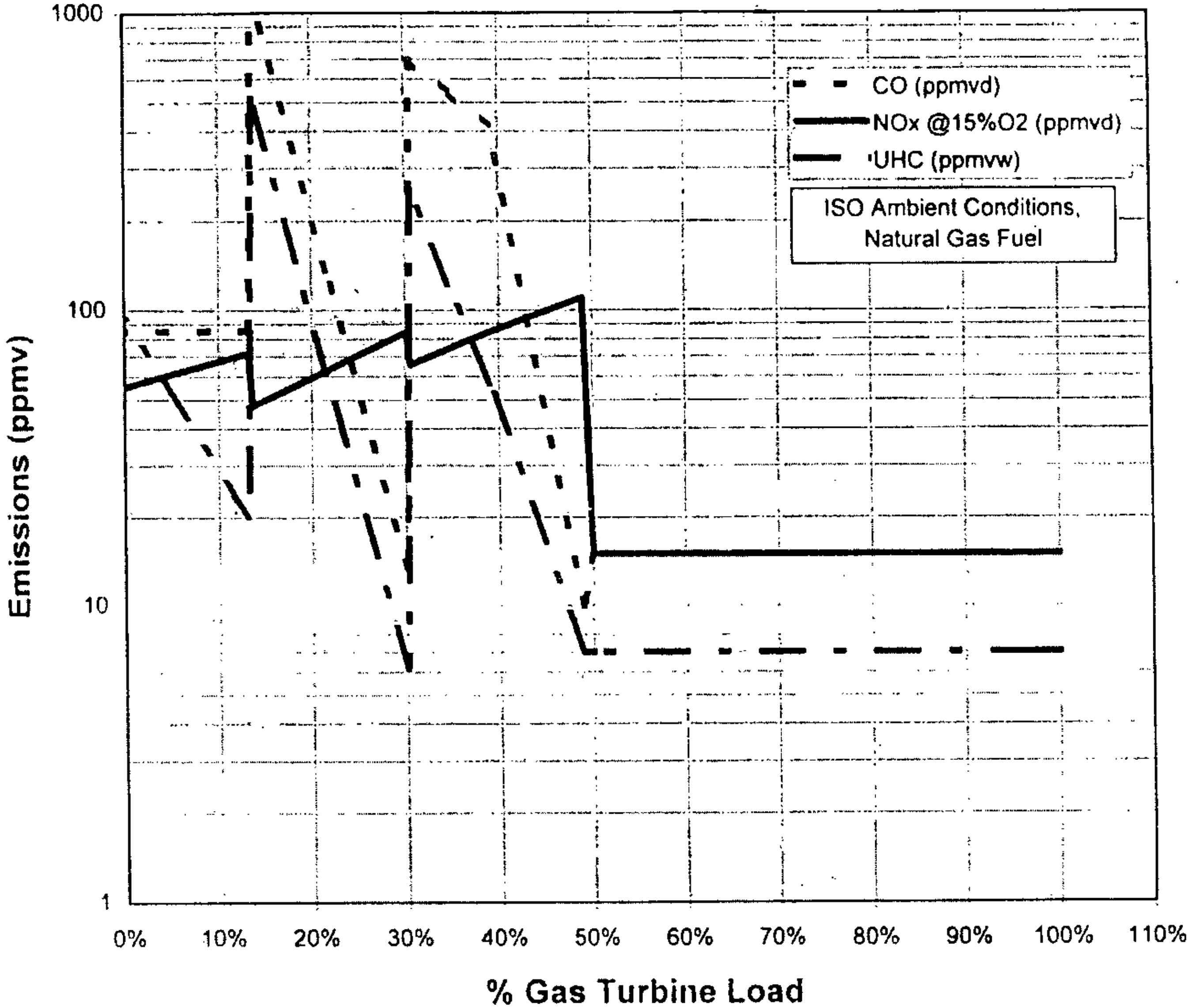

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

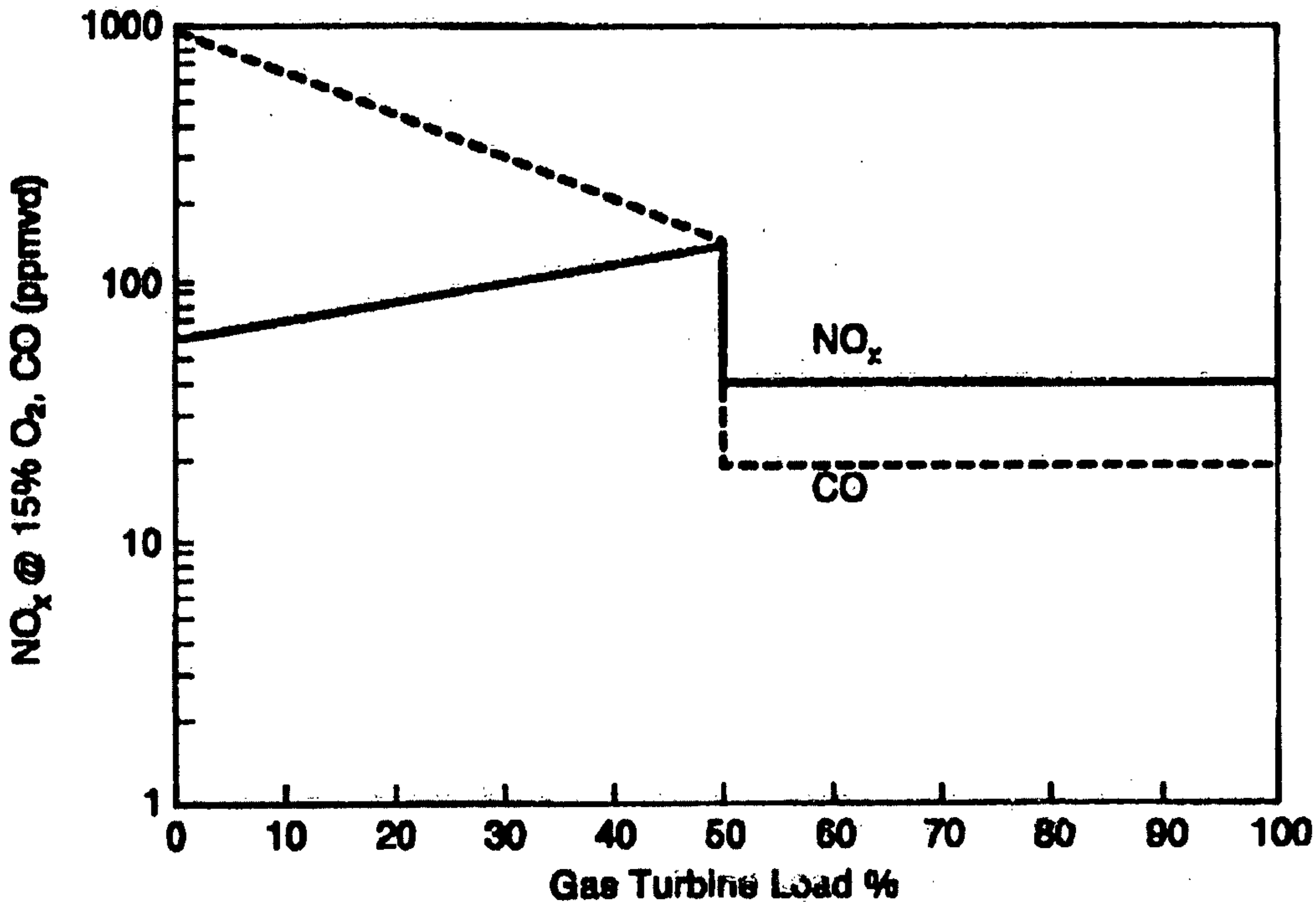

Figure 4 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 5 from an EPRI report.[5] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 5.

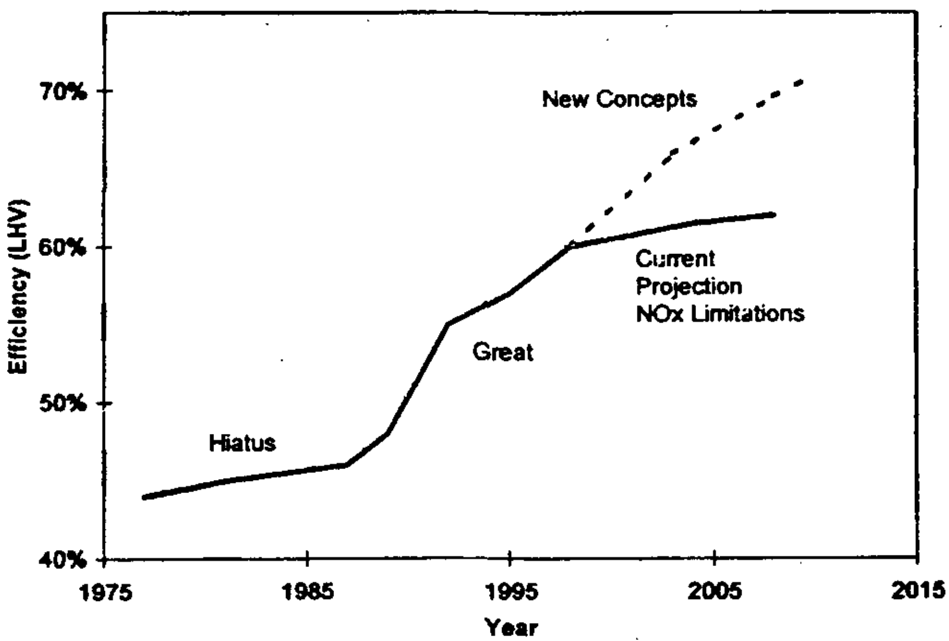

Figure 5 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by Midway. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air-cooling.

Catalytic Combustion: XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[6] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents. Westinghouse, for example, is working to replace the central pilot in its DLN technology with a catalytic pilot in a project with Precision Combustion Inc.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[7] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Recently, Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[8] The project will enter commercial operation by the summer of 2001. However actual installation of XONON™ is doubtful.

In principle, XONON™ will work on a simple cycle project. However, the Department does not have information regarding the status of the technology for fuel oil firing and cycling operations.

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 in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account 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. SCR units are typically used in combination with wet injection or DLN combustion controls.

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

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998.

Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 (Paynes Creek) project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority,[9] FPC, TECO, and Competitive Power Ventures will install SCR on combined cycle projects to achieve 3.5 ppmvd. Limits as low as 2 ppmvd NO_X have been specified using SCR on combined cycle F Class projects in various parts of the country.

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 Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

$SCONO_X$™ is a catalytic add-on technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[10]

California regulators and industry sources have stated that the first 250 MW block to install $SCONO_X$ ™ will be at PG&E's La Paloma Plant near Bakersfield.[11] The overall project includes several more 250 MW blocks with SCR for control.[12] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine equipped with $SCONO_X$™.

$SCONO_X$™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the $SCONO_X$ ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X.[13] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv.

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[14]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 190 TPY of SO_2 and 29 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf, but high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

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 and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such 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. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 119 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

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.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[15]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 9 and 30 ppmvd for gas and oil respectively at baseload proposed in Midway's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Midway for this project are 1.4 ppmvw for gas and fuel oil firing at baseload. These limits are sufficient to keep annual emissions of VOC below the 40 TPY threshold and a BACT determination is not required. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[16]

BACKGROUND ON PROPOSED GAS TURBINE

Midway plans to install three nominal 170 MW General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

Typically, companies obtain a guarantee from GE to achieve 9 ppmvd NO_X during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation. With the frequent start-ups and shutdowns of the units, some applicants are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, some of them agreed to a "new and clean" limit of 9 ppmvd but requested a continuing BACT limit of 10.5 ppmvd.

As detailed in the table above, the Department has issued quite a number of permits for simple cycle GE 7FA requiring achievement of 9-10.5 ppmvd without the requirement of any additional control equipment. The ones with limits of 9 ppmvd are allowed to operate for as many as 1000 hours per year on back-up fuel oil whereas the ones permitted at 10.5 ppmvd are allowed only 750 hours per year of fuel oil. A smaller GE unit known as the 7EA can routinely achieve 9 ppmvd NO_X or lower based on numerous installations in Florida and elsewhere. The 7EA has a lower flame temperature, compression ratio, and power rating (85 versus 170 MW) than the 7FA.

The ability to meet a NO_X emission limit of 9 ppmvd by DLN technology involves a substantial efficiency and energy penalty as previously discussed. For example, the 7FA is characterized by a 15.5:1 compression ratio, a 2400 °F firing temperature, 56 percent efficiency, and produces 263 MW in combined cycle. On the other hand, GE offers a more efficient F-Class model known as the 7FB, but guarantees a NO_X limit of 25 ppmvd by DLN.

The 7FB is characterized by an 18.5:1 compression ratio, a 2500 °F firing temperature, 57.3 percent efficiency, and produces 280 MW in combined cycle. The clear implication is that the power penalty to reduce NO_X from 25 to 9 ppmvd by DLN technology alone is on the order of 20 MW for a combined cycle (roughly 13 MW on a simple cycle unit).[17]

Another example of this point is the ABB GT24. It is characterized by a 30:1 compression ratio and 58 percent efficiency in combined cycle. The unit is guaranteed to meet 25 ppmvd of NO_X. The simple cycle version is rated at 183 MW compared to 170 for the GE7FA.

It is not surprising that some compromises were made by ABB, which resulted in greater power and efficiency but slowed progress toward single-digit NO_X emissions. According to ABB, "rather than just concentrating on ever lower NO_X levels, ABB has chosen a total solution that limits pollutants and at the same time increases energy efficiency."[18] A lower compression, lower efficiency version of the ABB GT24 might be capable of 15 ppmvd NO_X or less by DLN technology.

The results during the "new and clean" test of the GE PG7241 at the Polk Power Station (discussed above) are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits. For reference, the values while burning oil were equally good in comparison to the permitted limits for CO and VOC, whereas the NO_X emissions were very close to the permitted value of 42 ppmvd @15% O_2. Visible emissions were 0 percent opacity when firing natural gas or fuel oil.

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. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[19]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Midway project assuming full load. Values for NO_X and CO are corrected to 15% O_2 on a dry volume basis. 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 Nos. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 10/17 lb/hr – Gas/Fuel Oil (Front-half)
CO	As Above	9 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grain of sulfur per 100 ft^3 gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	9 ppmvd – Gas 42 ppmvd – F.O. for 1000 of 3,500 hrs

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are Hot SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- Hot SCR is not commonly required as BACT on simple cycle combustion turbines. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. It is noted that the specification of the fuel oil was 0.15 percent sulfur. This does not imply that hot SCR it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas with 0.05 percent sulfur fuel oil as back-up fuel.
- Hot SCR is required at the simple cycle continuous duty Lakeland McIntosh Unit 5 project if the Westinghouse 501 G unit fails to achieve 9 ppmvd while firing natural gas. Hot SCR was considered cost-effective because the unit will operate continuously and the expected NO_X reduction is from 25 to 9 ppmvd).
- The levelized costs of NO_X removal by Hot SCR for the Midway Project were estimated by ENSR at $20,700 per ton assuming 3,500 hours of dual-fuel operation. The estimates are based on emissions controlled to 4.5 and 7.5 ppmvd @15% O_2 NO_X while burning gas and fuel oil respectively and 5 ppmvd @15% O_2 ammonia slip.
- The levelized costs of NO_X removal by Hot SCR for the DeSoto project were estimated by Golder at $11,350 per ton assuming 3,390 hours of operation on natural gas and a reduction to 3.6 ppmvd on gas and 17 ppmvd on fuel oil. The estimates are based on an ammonia slip of 9 ppmvd for gas and 12 ppmvd for oil.
- The Department does not accept the precise hot SCR cost calculations presented by Midway and considers them on the high end. The costs calculated by Golder for the DeSoto Project are probably more accurate. With the actual performance of the GE 7FA at TECO Polk Power Station with no add-on control (5-8 ppmvd @15%O_2), it is easy to see that hot SCR would not be cost-effective. Hot SCR is rejected as BACT.
- The Department will limit operation of the three units to 3,500 hours per year per unit. No single unit may operate more than 5,000 hours per year to insure that the conclusion regarding cost-effectiveness remains applicable.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out

the possibility of $SCONO_X$. XONON is available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X. This value is equal to that required at the Lakeland continuous duty combustion turbine, which has an alternative hot SCR requirement.
- Typical permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, DeSoto, Virginia Power, and Midway while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42-ppmvd limit for limited fuel oil firing is typical.
- The gas-based NO_X emission limit of 9 ppmvd will be difficult to maintain over short term averaging times. That is the main reason why some operators cannot provide reasonable assurance they can meet such a low limit by DLN. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion.
- The Department issued permits for the TEC Polk Power, JEA Brandy Branch, and Reliant Osceola Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander, Vandolah, Shady Hills, and DeSoto.
- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[20]
- Based on test results at the JEA Kennedy Plant, it is possible that the NO_X emissions while firing oil from may be reduced from 42 to 30 ppmvd. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.

- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- The fuel oil-based NO_X emissions limit of 42 ppmvd can be maintained over a short-term averaging period by varying the amount of water injected. The Department has determined that a 3-hour averaging time is appropriate.
- The Department's overall BACT determination is equivalent to approximately 0.4 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- The applicant estimates VOC emissions of 1.4 ppmvd while firing gas and 1.4 ppmvd while burning fuel oil. The Department will set the limits at 2.8 ppmvd because at this concentration, the project will still not trigger PSD or a requirement for a BACT determination.
- The Department will set CO limits achievable by good combustion at full load as 9 ppmvd @15% O_2 (gas) and 20 ppmvd (oil). These values are in the lower range of values from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- Midway estimated levelized costs for CO catalyst control at $31,800 per ton. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- Golder evaluated the use of oxidation catalyst for the DeSoto project with 90 percent control efficiency. Golder estimated levelized costs for CO catalyst control at $7,500 per ton.
- The cost of CO control by oxidation catalyst is probably closer to the Golder estimate based on reducing *permitted* CO emissions. However in view of the performance of GE 7FA units without add-on control (~1 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will not set a continuous CO limit reflecting the "new and clean test" because GE will not guarantee it. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- There is no benefit in penalizing the applicant or with a lower limit at this time just because the performance at another site was far better than guaranteed or expected.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limits for PM_{10} will be set at 10 pounds per hour during gas operation and 17 pounds per hour while operating on fuel oil. These values are based on front-half catch.

- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power, DeSoto Power, Vandolah, Shady Hills and quite a number of combined cycle projects.

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Carbon Monoxide	Annual Method 10
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (gas - 24-hr block average) (oil – 3-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed. During gas operation, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. 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. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C.
SO_2 and SAM	Custom Fuel Monitoring Schedule- Refer to Appendix GG

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

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

Date: 2/14/01

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 2/14/01

REFERENCES

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2 Summary. "Initial Compliance Testing at the JEA Kennedy Plant." January 2001.

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APPENDIX GG
40 CFR 60 NSPS REQUIREMENTS FOR GAS TURBINES

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

<u>Department requirement</u>: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide*. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\,e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.
Noxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

<u>Department requirement</u>: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20

following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The 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.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (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.

Memorandum

Florida Department of Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy

FROM: Al Linero
Teresa Heron

DATE: February 12 , 2000

SUBJECT: Midway Energy Center
Three 170 MW Combustion Turbines
DEP File No. 1110099-002-AC (PSD-FL-305)

Attached is the final package for construction of three dual-fuel, intermittent duty, simple cycle, 170 MW GE 7FA combustion turbines with inlet air chillers, two fuel oil storage tanks, a gas heater, and ancillary equipment at the planned (Enron) Midway Energy Center in St. Lucie County.

NO_X emissions from the combustion turbine will be controlled to 9 ppmvd Dry Low NO_X (DLN-2.6) technology while firing natural gas. The facility may operate 3,500 hours per year per unit. Use of fuel oil (during which emissions of 42 ppmvd are allowed) will be permitted up to 1000 hours per year per unit.

Conditions in the draft permit required Midway to burn more gas than oil. Midway did not petition the permit, but asked relief from this condition based on claims that the gas supply is actually uncertain during the first few years of operation.

To insure there is still a big incentive to fire gas when available and to encourage further development of firm supplies in the area, Midway proposed a condition that will result in cutbacks in total hours of operation after Midway fires 250 hours per year per unit. For example, if Midway actually burns fuel oil for 1000 hours each unit can only operate for 2000 hours.

The permit will also require Midway to examine the possibility of NO_X reductions (from 42 ppmvd) while firing fuel oil. We are aware that JEA achieved 30 ppmvd while firing fuel oil during the initial compliance test at their GE 7FA unit at the Kennedy Plant.

We are reviewing almost two identical applications from Enron in Broward County. I expect similar permits unless any Class I Area issues are raised by the National Park Service.

We recommend your approval of the attached Intent to Issue.

AAL/al

Attachments

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

RECEIVED
JAN 17 2001
BUREAU OF AIR REGULATION

January 16, 2001

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

RE: Midway Development Company, LLC
Revised Permit Application for Midway Energy Center

Dear Mr. Linero:

On behalf of Midway Development Company, LLC, enclosed for your records are four (4) copies of a revised air permit application for the Midway Energy Center electric generating plant in St. Lucie County, Florida. This revised application addresses the reduction in hours of oil use from 1500 to 1000 and a change in the requested emission limit for NOx from 12 ppm to 9 ppm when firing natural gas.

Our consultant ENSR had previously sent you an electronic copy of this revised application.

If you have any questions, please don't hesitate to call me at (713) 853-3161.

Sincerely,
Enron North America

David A. Kellermeyer

David A. Kellermeyer
Director

Enclosures

cc: Mr. Lennon Anderson, DEP West Palm Beach

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

February 2, 2001

RECEIVED

FEB 05 2001

BUREAU OF AIR REGULATION

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

Re: DEP File No. 1110099-002-AC (PSD-FL-305)
Midway Energy Center, St. Lucie County
Comments on Draft PSD Permit

Dear Mr. Linero:

This letter serves to provide comments on the draft permit for the above-referenced facility. The Department issued the Draft Permit, Technical Evaluation and Preliminary Determination on December 15, 2000. Comments are provided below, in the order in which they occur in the draft permit.

1. Section II. Administrative Requirements, Specific Condition (SC) 8 (page 5 of 15): At our request, the permit expiration date was extended. However, we believe it was the Department's intent to revise the language as follows: "The expiration date is June 30, 2003. Physical construction shall be complete by December 31, 200<u>2</u>~~3~~."

2. Section III. General Operation Requirements, SC 13 and 14 (pages 7 and 8 of 15): As suggested in a separate letter to the Department, dated January 23, 2001 (attached), it's requested that the language in SC 13 and 14 be revised based on the discussions in our meeting held in your offices on January 17, 2001. The attached letter provides suggested language that provides the Department with reasonable assurance that the intent is for natural gas to be the primary fuel for this proposed project.

3. Section III. SC 17 (page 8 of 15): The permit language states that "The permittee shall provide manufacturer's emissions vs. load diagrams for the DLN and wet injection systems prior to their installation." Past requests of the manufacturer for these types of diagrams have been unsuccessful. Typically, the manufacturer will provide emission estimates at various load points corresponding to various inlet temperature cases. These emission values, that are the basis for this permit, were previously provided in the permit application. It's requested that the word "diagrams" in the above sentence be replaced with the word "estimates".

4. Section III. SC 19 (page 9 of 15): The language concerning fuel oil firing should be revised as follows: "In addition, NO_x emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd at 15% O_2 to be demonstrated by <u>initial</u> stack test."

5. Section III. SC 20 (page 9 of 15): The CO emission limit for fuel oil presented in the permit application was based on 20 ppmvd. At a temperature of 30 F, this corresponds to 69.6

lb/hour, not 46 lb/hour, as shown in the draft permit. The 20 ppm concentration is based on 100% load. Concentrations of CO are estimated to be as high as 22 ppm at 75% load factor and 30 ppm at 50% load factor. The peak emission estimate is 78.3 lb/hour at 50% load and 91 F. Based on these factors we request that the permit limit for oil firing be expressed as follows: "The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 31 lb/hr (gas) and neither 20 ppmvd nor 70 lb/hour (fuel oil) to be demonstrated by stack *tests at full load operation.*"

6. Section III. SC 27 (page 10 of 15): The last sentence should be revised as follows: "...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. ~~18 and~~ 19."

7. Section III. SC 29 (page 11 of 15): The permit language indicates that emission testing by EPA Reference Methods 9 and 10 (for visible emissions and CO emissions, respectively) are to be conducted both initially and annually for both fuels. In the past, the Department has issued permits (e.g., Hines Energy Complex) with language that requires that annual testing be done on fuel oil (the backup fuel) only if a threshold number of operating hours on oil is exceeded (e.g., 400 hr/CT) during a rolling 12-month period. This is because it's a financial hardship to require operation on the more expensive fuel. It's requested that the conditions be revised to include annual testing for VE and CO emissions on oil, only if a CT exceeds 400 hours of operation in a 12-month rolling period.

8. Section III. SC 33 (page 11 of 15): It's requested that the same language be included here regarding the annual testing requirement for visible emissions while firing oil.

9. Section III. SC 36 (page 12 of 15): The second sentence should be revised as follows: "...corrected for the average inlet ~~ambient~~ air temperature during the test...".

10. Section III. SC 45 (page 13 of 15): The last sentence states that "these excess emissions periods shall be reported as required in Specific Conditions 24 and 46." The reference to SC 24 appears to be incorrect, as it refers to the limitation for visible emissions.

11. Section III. SC 46 (page 14 of 15): Although the language is intended to instruct on the procedure to determine compliance with the 24-hour rolling average, the second sentence refers to a separate compliance determination being conducted at the "end of each operating day". This language is appropriate in the context of a 24-hour block average, but should be deleted from SC 46, which is addressing rolling averages.

12. Section III. SC 47 (page 14 of 15): The Specific Conditions referenced in the last sentence of this condition (20, 21 and 29) all appear to be incorrect. The conditions need to be cross-referenced correctly or deleted. Also, the appropriate DEP office to notify would be the Southeast District, not the South District.

13. Section III. SC 49 (page 14 of 15): Some of the text appears to be missing. The doesn't appear to be any schedule for testing of sulfur or nitrogen in natural gas in the bulleted items. In fact, the bulleted items appear to be related to compliance with the Acid Rain requirements of Parts 72 and 75, not with Part 60 Subpart GG compliance (which is what requires a Custom Fuel Schedule).

14. Section III. SC 50 (page 15 of 15): It's requested that the requirement to conduct sampling and analysis for fuel bound nitrogen content be deleted. Typically, the requirement to monitor water-to-fuel ratio, combined with the requirement to analyze for fuel bound nitrogen content, provides a surrogate for NOx compliance. As recognized by the Department in the language of SC 48, the NOx CEMS are to be used in lieu of the water/fuel monitoring system for reporting excess emissions. Given that NOx CEMS will be used for compliance, the monitoring of the fuel bound nitrogen content serves no useful purpose, and should not be required.

If you should have any questions concerning these comments, please do not hesitate to contact me at (713) 853-3161.

Sincerely,

David A. Kellermeyer

David A. Kellermeyer
Authorized Agent

Attachment

cc: Greg Krause
Raimund Grube
Ben Jacoby
Scott Osbourn, ENSR

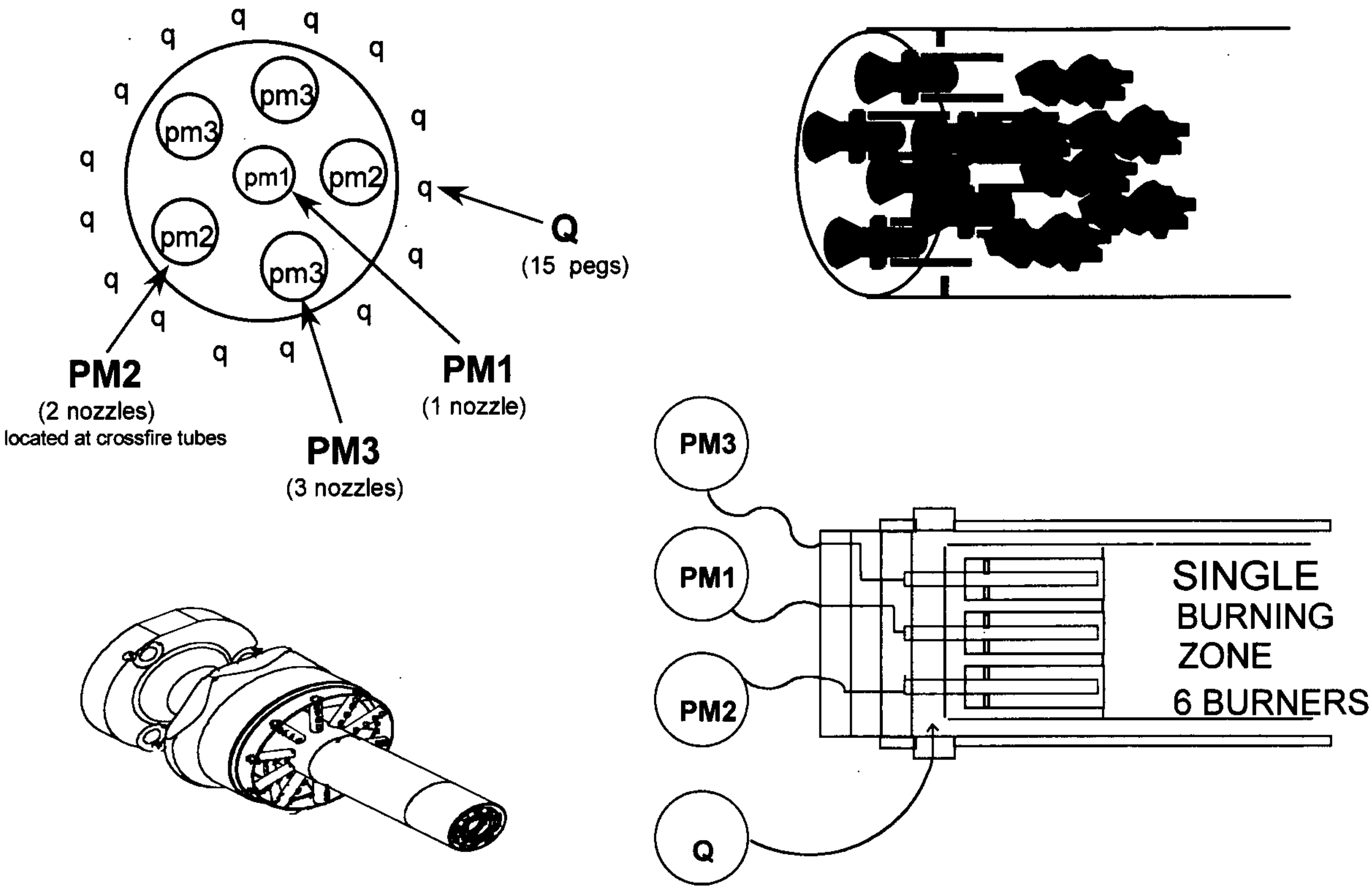

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

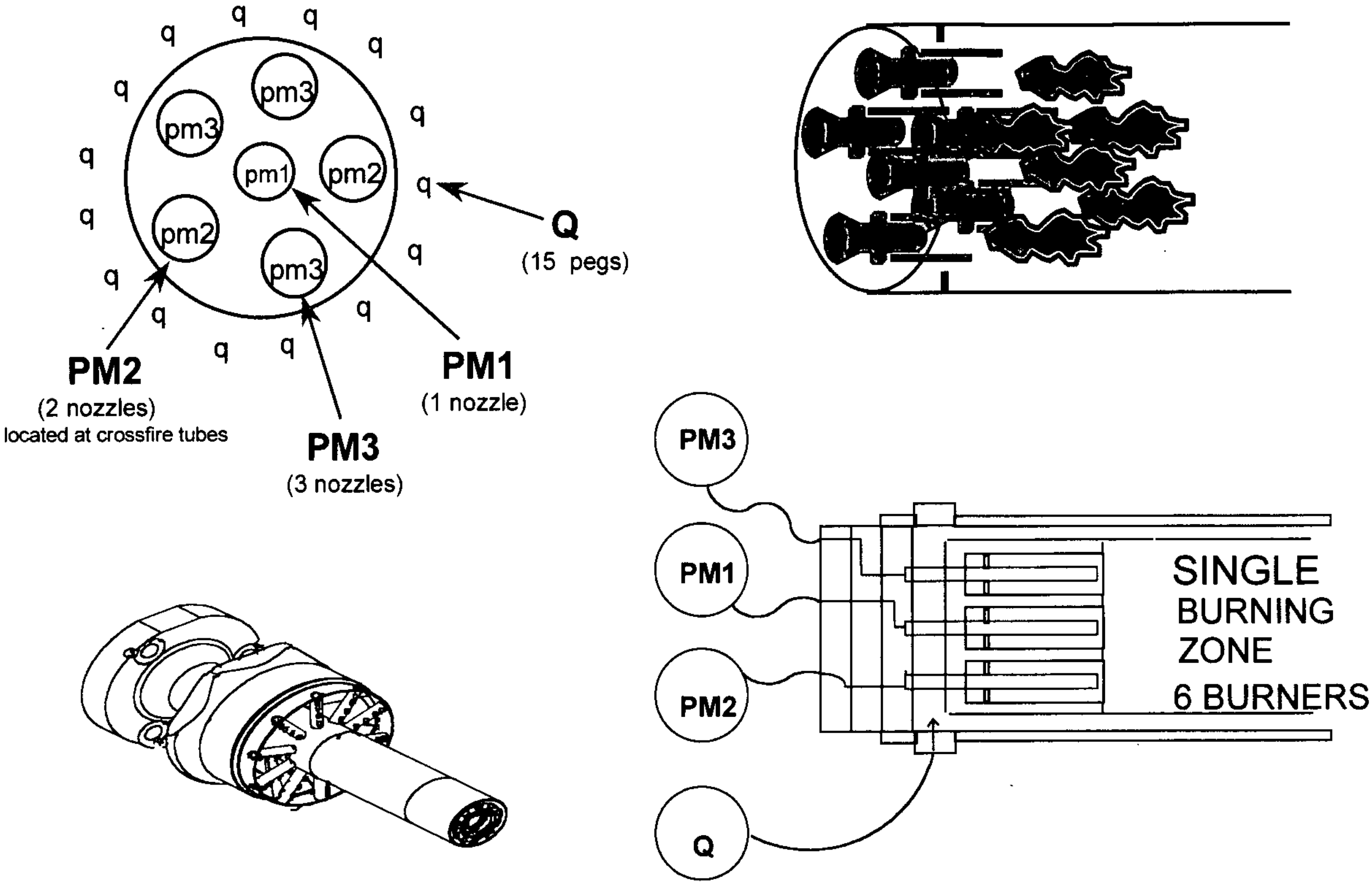

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

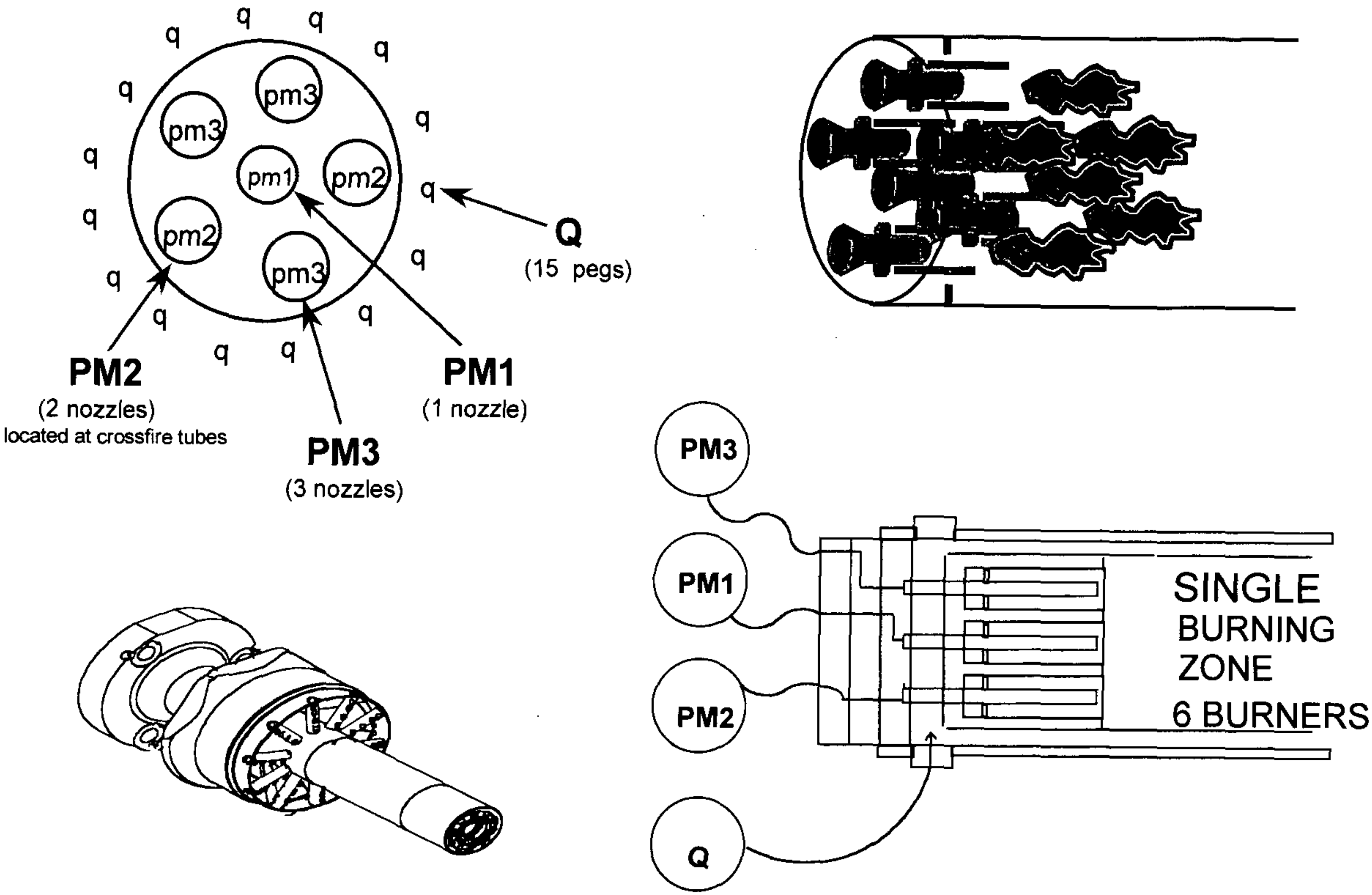

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

DEP File No. 1110099-002-AC (PSD-305)
Midway Energy Center, Units 1 – 3
St. Lucie County

Enclosed is the Final Permit Number PSD-FL-305 to construct three 170-megawatt dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located in St. Lucie 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.

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 2/14/01 to the person(s) listed:

Ben Jacoby, MDC*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Chair, St. Lucie County BCC
Blair Burgess, P.E., ENSR

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 2/14/01
(Clerk) (Date)