STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. John S. Ellis
IPS Avon Park Corporation
1560 Gulf Boulevard
Clearwater, Florida 32767

DEP File No. 0490043-001
Permit No.: PSD-FL-275
Vandolah Power Project
Hardee County

_______________________________/

Enclosed is the Final Permit Number PSD-FL-275 to construct: four nominal 170 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generators with 60-foot stacks and two 2.8 million gallon fuel oil storage tanks for the proposed Vandolah Power Project to be located at 2394 Vandolah Road, near Wauchula, Hardee 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 12-16-99 to the person(s) listed:

John S. Ellis, IPSAPC*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Ken Kosky, P.E., Golder Associates
Chair, Hardee County BCC

Clerk Stamp

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

_________________ (Clerk) 12-16-99 (Date)

FINAL DETERMINATION
VANDOLAH POWER PROJECT
HARDEE COUNTY
FOUR SIMPLE CYCLE COMBUSTION TURBINES

The Department distributed a Public Notice package on October 18, 1999 for the project to construct a nominal 680 megawatt (MW) natural gas and distillate fuel oil-fired simple cycle power plant near Wauchula, Hardee County. The project includes: four nominal 170 MW combustion turbine-electrical generators with 60-foot stacks and two 2.8 million gallon distillate fuel oil storage tanks. The Public Notice of Intent to Issue was published on October 21 in The Herald Advocate in Wauchula.

No comments were received by the Department from the public or the Fish and Wildlife Service pursuant to the Notice. However the Fish and Wildlife Service submitted comments on the original application. These were considered prior to issuance of the Public Notice package.

Comments were received from the U.S. Environmental Protection Agency (EPA) in a letter dated November 19. A letter also dated November 19 was received from EPA approving the Custom Fuel Monitoring Request proposed in the Public Notice Package.

Comments were received from Golder Associates on December 13 on behalf of IPS Avon Park Corporation. Most of their comments were in response to EPA's comments. Following are the comments received from EPA and Golder followed by the Department's responses:

1. **(EPA)** The SCR Cost analysis provided by the applicant in the PSD application lists an "Annualized Total Direct Recurring" cost that is factored in the indirect annual cost figure. This recurring cost seems to be double counting the "Total Direct Annual Costs" which already incorporate the recurring cost of SCR catalyst and its disposal. The recurring cost should be omitted from the cost analysis unless a detailed explanation for its purpose can be provided.

   Additionally, the "MW lost penalty" figure seems to be accounting for the lost revenue during catalyst replacement. Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue from catalyst replacement should not be included in the cost analysis. The replacement of catalyst can be accomplished during a regularly scheduled shutdown for routine maintenance and repair. The lost revenue figure should be omitted from the cost analysis.

   (Golder) Annualized Total Direct Recurring Costs: This annualized cost is based on only the annualized cost of the "Hot" SCR catalyst (i.e., 0.3811 times the $2.458 million catalyst cost for an annualized cost of $936,700). Since the catalyst is a significant cost associated with the SCR system and has a shorter life than the other equipment (i.e., 3 years), the annualized cost is based on the 3 year catalyst life and a 7 percent capital recovery factor (CRF). The Annualized Total Direct Capital Cost, which is based on 15 years, does not include the catalyst. Also, the Direct Annual Costs do not include the cost of the catalyst replacement. This is directly handled by the Recurring Capital Costs and associated annualized cost calculation. There is a cost to account for carrying chargers for one-third of a catalyst, but this cost is relatively minor. It should be noted that the traditional method included in the OAQPS

Cost Control Manual is to annualize the capital costs associated with the pollution control equipment and include a separate cost for replacement parts (e.g., catalyst). If this approach is used, the annualized cost of the catalyst and the direct annual cost of catalyst replacement together is about $1,107,870 (i.e., 0.1174 times $2.458 million plus 1/3 of $2.458 million).

The MW Loss Penalty reflects the cost for the catalyst replacement outside of normal maintenance. Moreover, the regularly scheduled maintenance typically occurs at about 5,000 hours of turbine operation, which may not coincide with the requirements to replace catalyst modules. This cost is especially valid for simple cycle turbines where "hot" SCR has not been demonstrated of cycling turbines, let alone "F" Class sized turbines. It should be noted that the annual cost for MW Loss Penalty is low relative to the other costs (i.e., less than 5 percent) and would not affect the conclusions.

(Department) The Department clearly stated in the Draft BACT that it does not necessarily adopt the precise cost calculations for the Vandolah Power Project. Adopting EPA's recommendations will lower the cost-effectiveness value somewhat, but not to the point of cost-effectiveness. The Department did a more detailed analysis of the costs of Hot SCR on the similar Reliant Energy Project and estimated NO_X removal cost-effectiveness closer to $10,000 per ton (starting at a higher NO_X value prior to SCR control). Golder suggests that the costs are even higher than initially estimated. The Department notes that Hot SCR has rarely been applied on intermittent duty simple cycle turbines in attainment areas and that the NO_X limit on gas is the lowest value for such a unit an attainment area. More careful cost-effectiveness analysis will be performed by the Department, particularly when emissions of NO_X are inherently higher than they are for the Vandolah Project.

2. **(EPA)** In Section III, Condition 19 of the draft permit, the emission rate for NO_X is set as 9 ppmvd on a 24-hour block as measured by CEMS. The averaging period for these emission limits should be much shorter, consistent with the 3-hour rolling average proposed for fuel oil combustion in Condition 19. In previous recent correspondence from the Florida Department of Environmental Protection (FDEP) regarding similar sources, the main reason for the inconsistency in averaging times is credited to the fluctuations in emissions resulting from load changes. Elevated emissions from intermittently operated combustion turbines are most likely to occur during startup and shutdown periods, which FDEP has already taken into account in their excess emissions language. Although we take exception to the excess emissions provision (see our next comment below), a compliance averaging period less than 24-hours is reasonable if the excess emission provision is retained. Furthermore, the planned intermittent operation of the facility means that the combustion turbines will seldom operate for 24 consecutive hours.

   (Golder) NO_X Emission Limit Averaging Time: The 24-hour block average proposed by the Department for the NO_X emission limit when firing natural gas of 9 ppmvd corrected to 15 percent oxygen is appropriate for the proposed project. The benefits of NO_X control through the use of pollution prevention technology, such as the dry low-NO_X (DLN) combustor proposed for the project, suggests that a longer averaging time is warranted. All combustion processes have some variability and while the GE DLN combustor is designed to meet the 9 ppmvd limit at 6 standard deviations, a block average will account for any individual combustor variability and any associated degradation over time. Moreover, there is no environmental benefit from a shorter averaging time, since the block emission limit will assure low NO_X emissions during daily periods (e.g., periods of ozone formation). It should also be apparent that the 24-block average will be applicable even if a turbine does not operate over a single 24-hour period. In such cases, the 24-hour block limit would apply to valid operating hours that are accumulated with further operation as indicated in Condition 19. This would exclude valid excess emissions from startup, shut down or malfunction. However, the periods of excess emissions are expected to be shorter than 2-hours given that the GE DLN combustor can meet the emission limit starting at 50 percent load and the units are designed to supply electric in short time periods.

(Department) The 9 ppmvd NO_X limit together with the averaging time reflects the Department's professional opinion regarding BACT for this simple cycle intermittent duty 7FA combustion turbine. After exclusion of startup and shutdown, the Department requires that NO_X emissions average 9 ppmvd during the hours of a 24 hour day that it actually operates. The average will not be smeared over all 24 hours in a day.

The three hour average for the fuel oil limit is more easily achievable because the amount of water injected can be adjusted easier within a time block to achieve the required 42 ppmvd limit. The Department required a 3 hour averaging time for the recent KUA combined cycle project while burning gas. The reason is that the ammonia can be varied to compensate within the same time block. There is no way to easily do this with DLN technology. If the averaging time should be 3 hours, the Department will increase the limit accordingly to a value higher than 9 ppmvd.

The Department believes that it will be a challenge as it is to achieve the 9 ppmvd limit. The physical characteristics of the unit also reflect BACT. There is nothing to indicate that it will be operated in any way outside of a BACT compliant unit.

Some consideration was given to requiring compliance with a 24-hour pound per hour limit (in lieu of a ppmvd limit) based on the maximum emissions that can be emitted from the unit at full load . This would not increase Potential to Emit. However it would cover the startup and shutdown periods.

There is little doubt that the unit will be rapidly taken through the diffusion flame phase and to the fully pre-mixed phase as it reaches full load.

3. **(EPA)** As indicated in Conditions 25 and 26 of the draft permit, FDEP is proposing to allow excess emissions due to startup, shutdown, malfunction for up to 2 hours in any 24-hour period. It is the Environmental Protection Agency's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operations of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

(Golder) Excess Emissions: Conditions 25, 26 and 27 are appropriate and valid excess emission limitations provided for in Rule 62-210.700 Florida Administrative Code. Indeed, Condition 26 requires the applicant to operate the system properly to reasonably prevent excess emissions. Also, as indicated in the Department's BACT evaluation, the operation of the GE DLN combustion technology is fully automated to assure that excess emissions will be minimized.

(Department) As shown in Figure 2 on the BACT, the fully pre-mixed mode for the Dry Low NO_X combustor is not attained until 50 percent of full load. In contrast to a combined cycle unit, the amount of time needed for a startup or shutdown is actually very short. Typically, the units can probably reach 50 percent of full load within 15 minutes and most likely within a half hour. Although the 9 ppmvd limit will not be achieved during these times, the unit will likely emit less than the allowable pounds per hour during the combined hours allowed for startup and shutdown.

The unit to be constructed is clearly and physically the BACT for simple cycle units. It would be very difficult to fix a BACT emission limit for those periods and the definition of BACT allows a work practice. That practice is basically adherence to the equipment manuals. Achievement of the 9 ppmvd limit outside of startup and shutdown will also provide reasonable assurance that the equipment will be operated properly at all times.

4. **(EPA)** The new CTs, which will fire No. 2 fuel oil as backup fuel, have potential to emit VOCs from two 2.8 million gallon fuel oil storage tanks. Any VOC emissions from the storage tanks should be taken into account when calculating the Potential to emit (PTE) for VOC emissions. We realize the VOC emissions from these tanks will be small; however, as a matter of completeness, this increase in emissions should be included in all PTE calculations.

   (Golder) Department response. VOC Emissions from Tanks: As provided for in the instructions to DEP Form 62-210.900(1), the emissions for the tanks were not included since the emissions of VOC would be less than 5 tons/year and there are no applicable emission limits. The maximum potential VOC emission for these tanks will be less than 1 ton/year. Adding these emissions would not change the PSD applicability for the project.

   (Department) The Department agrees with EPA and Golder and will add 1 ton per year to the Potential-to-Emit estimates.

5. **(EPA)** Operational Configuration Worst Case – Although the air impact assessment was performed for various loads and ambient temperatures, all four combustion turbines were assumed to operate simultaneously at the same load. This is not a realistic assumption and may not provide the operating scenario producing the worst case ambient impacts. However, it is recognized that because of the very low maximum concentrations reported, it is unlikely that operations with variable loads per turbine will alter the impact conclusions in the preliminary determination.

(Golder) Operational Configuration Worst Case: Golder Associates agrees with EPA's observation that modeling performed at three different loads and turbine inlet temperatures are not realistic. However, based on hundreds of modeling studies, this approach produces unrealistically high (i.e., conservative) impacts relative to normal operation and meteorological conditions. For the IPS Vandolah Project where there are identical sources located relatively close together and where downwash is not a significant factor, a modeling approach suggested by EPA would not produce the highest impacts (e.g., two turbines at 100 percent load and two turbines at 50 percent load).

(Department) Although the air impact assessment assumed that all four of the combustion turbines were operating simultaneously at the same load, the Department believes that this method was suitable for determining the worst case scenario for ambient air quality impacts. Modeling the turbines at different loads would produce minimal changes, and would not significantly impact the results that are reported in the preliminary determination.

6. **(EPA)** ISCST3 Model Version – The ISCST3 version used was indicated to be 98356. This is an older version. Future modeling should use the most recent version – 99155.

   (Golder) ISCST Model Version: The EPA comment is acknowledged. It should be noted that Version 99155 was made available about the time the modeling was performed and for the proposed project the changes made to the new version would not have produced different impacts than the use of Version 98356.

   (Department) The Department will require all future projects to be modeled with the latest version of the ISCST3 model, which is currently version 99155. The Model Change Bulletin dated 99155 for the ISCST3 model does not indicate that any of the changes made to the model between version 98356 and version 99155 will have an impact on the modeling that was conducted for this project.

7. **(EPA)** Modeling Error – Appendix C of the PSD permit provides a listing of the input files used for base load natural gas operation at 95 °F ambient temperature. A stack exit velocity of 38.86 meters per second (m/s) was used when Table 2-1 indicates it should be 33.8 m/s.

   (Golder) Modeling Error: The EPA comment is acknowledged. A transcription error was made in the exhaust gas velocity for the 95 °F turbine inlet temperature. The maximum impacts were, however, for oil firing.

   (Department) It appears that an error was made on the stack velocity input into the ISCST3 model when the case of base load natural gas operation at 95 °F was modeled. However, natural gas operation usually has much lower impact on ambient air quality than fuel oil operation. The fuel oil operation scenario was modeled correctly, therefore, the maximum impacts from the proposed project that are reported in the preliminary determination are accurate.

CONCLUSION

The final action is to issue the permit as proposed with minor changes in the BACT write-up.

Z 031 391 903

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PS Form **3800**, April 1995

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John Ellis
IPS Avon Park Corp
1560 Gulf Blvd
Clearwater, Fl
32767

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Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

IPS Avon Park Corporation
1560 Gulf Boulevard, # 701
Clearwater, Florida 32767

File No.	PSD-FL-275
FID No.	0490043
SIC No.	4911
Expires:	January 1, 2002

Authorized Representative:

John S. Ellis

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: four dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators; two 2.8-million gallon fuel oil storage tanks; and four 60-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 at 2394 Vandolah Road, which is approximately 7 miles West of Wauchula, Hardee County. UTM coordinates are: Zone 17; 407.85 km E; 3044.5 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 BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install four dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with four 60-foot stacks and two 2.8-million gallon fuel oil storage tanks. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emissions Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
005	Fuel Storage	One 2.8 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	One 2.8 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 12/15/99 Issued Final Permit
- 10/21/99 Notice of Intent published in The Herald Advocate
- 10/18/99 Distributed Intent to Issue Permit
- 09/29/99 Application deemed complete
- 08/31/99 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 August 31, 1999
- Refined PSD Class I Significant Impact Analysis and Regional Haze Analysis Report received October 12, 1999
- Department's Intent to Issue and Public Notice Package dated October 18, 1999
- EPA letter dated November 19 regarding draft Permit and draft BACT
- EPA letter dated November 19 approving Custom Fuel Monitoring Schedule
- IPS Avon Park Corporation (Golder) letter dated December 13, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 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 DEP Southwest District office, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 and phone number 813/744-6100.
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. 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: 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, low or baseload operation (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.]

SECTION II. ADMINISTRATIVE REQUIREMENTS

8. 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 Southwest District office. [Chapter 62-213, F.A.C.]
9. 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.]
10. 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 Southwest District office by March 1st of each year. [Rule 62-210.370(2), F.A.C.]
11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
12. Permit 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.]
13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Southwest District office. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emission Units 001-004, Power Generation, consisting of four 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.]
5. ARMS Emission Units 005-006, Fuel Storage, consisting of two 2.8 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. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District.

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}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-4) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,612 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,806 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 Southwest 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 stationary gas turbines shall only operate up to 3,390 hours including up to 1000 hours on fuel oil during any calendar year. [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 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 [Rule 62-210.200, F.A.C. (BACT)]

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

Control Technology

15. Combustion Controls: 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. Water Injection: 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. Control System Characteristics: The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. 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. Emission Limit Summary: Following is a summary of the emission limits and required technology. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10/17 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC	As Above	1.4 ppmvd (Gas) 7 ppmvw (Fuel Oil)
CO	As Above	12 ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	1 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 (Gas) 42 ppmvd (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 (of valid hours during which the unit is operated only) as measured by the continuous emission monitoring system (CEMS). Refer to Condition 30 for valid hours contributing to the block average.

In addition, NO_X emissions calculated as NO_2 shall not exceed 64.1 pounds per hour (at ISO conditions) and 9 ppmvd @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. [Rule 62-212.400, F.A.C.]

- While firing Fuel Oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3-hr average (of valid hour hours during which the unit is actually operated only) as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 351 lb/hr (at ISO conditions) and 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

  The permittee shall develop a NO_X reduction plan when the hours of oil firing reach the allowable limit of 1000 hours per year. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without 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. [BACT Determination].

20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 42.5 lb/hr (at ISO conditions) while firing gas and neither 20 ppmvd nor 71.4 lb/hr (at ISO conditions) while firing fuel oil. The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.4 ppmvw nor 2.8 lb/hr (ISO conditions) and neither 7 ppmvw nor 16.2 lb/hr (ISO conditions) while operating on oil to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

22. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 1 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year per unit. Emissions of SO_2 (at ISO conditions) shall not exceed 5 lb/hr (natural gas) and 98.7 lb/hr (fuel oil) as 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 not exceed 10 lb/hr when operating on natural gas and shall not exceed 17 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

24. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions and shall not exceed 10 opacity. 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. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).

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 Southwest 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. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

28. Compliance with Emission Standards: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial Performance Tests: 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 (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. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (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 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). 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 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. These excess emissions periods shall be reported as required in Conditions 25 and 26. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

    - All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. 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. [40CFR60.13]

31. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

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

33. Compliance with the VOC emission limit: 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.

34. Testing procedures: 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 ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 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.

35. Test Notification: The DEP's Southwest District 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).

36. 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.

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by IPSAPC 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.

39. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition No.36 above. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

40. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on these Units shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C, 40 CFR 75and 40 CFR 60.7 (1998 version)].

41. CEMS for reporting excess emissions: 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 40CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions No 18 and 19, shall be reported to the DEP Southwest District within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).

42. 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 (1998version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS

43. 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.

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

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

    - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).

- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

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

45. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

46. Determination of Process Variables:

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

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Vandolah Power Project
PSD-FL-275 and 0490043-001-AC
Hardee County, Florida

BACKGROUND

The applicant, IPS Avon Park Corporation (IPSAPC) proposes to install four nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Vandolah Power Project near Wauchula, Hardee 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), volatile organic compounds (VOC), 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 60-foot stacks. IPSAPC proposes to operate these units up to 3,390 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.5 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 October 15, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on August 31, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Golder Associates.

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) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	10 pounds per hour (gas) 17 pounds per hour (oil)
Carbon Monoxide	As Above	12 ppmvd (gas, baseload) 20 ppmvd (oil baseload)
Volatile Organic Compounds	As Above	1.4 ppmvd (gas, baseload) 7 ppmvw (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	1 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

According to the application, the maximum emissions from the facility will be approximately 1008 tons per year (TPY) of NO_X, 346 TPY of CO, 82 TPY of PM/PM_{10}, 221 TPY of SO_2, 34 TPY of SAM, and 47 TPY of VOC.

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 IPSAPC is within the NSPS limit, which allows NO_X emissions, over 100 ppmvd for the high efficiency units to be purchased for the Vandolah Power Project.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The IPSAPC Vandolah Power Project 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
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Draft 11/99. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 12/99. 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 Draft 11/99. 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 Application 10/99. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Application. 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 Application. 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 ppmvd NO_X limit on gas Draft 5/98. 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 ppmvd 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 ppmvd are on 1/24 hr basis Issued 1/99. 800 hrs on oil
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 ppmvd 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 - ppmvd (or as indicated)	VOC - ppmvd (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
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	1.8 – NG	9 lb/hr - 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
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
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
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

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

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

- Comments from EPA Region IV dated November 19, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for JEA Brandy Branch Station Project
- GE Combustion Turbine Startup Curves
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

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.

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 Vandolah 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 Vandolah 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.

Combustion Controls

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

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

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

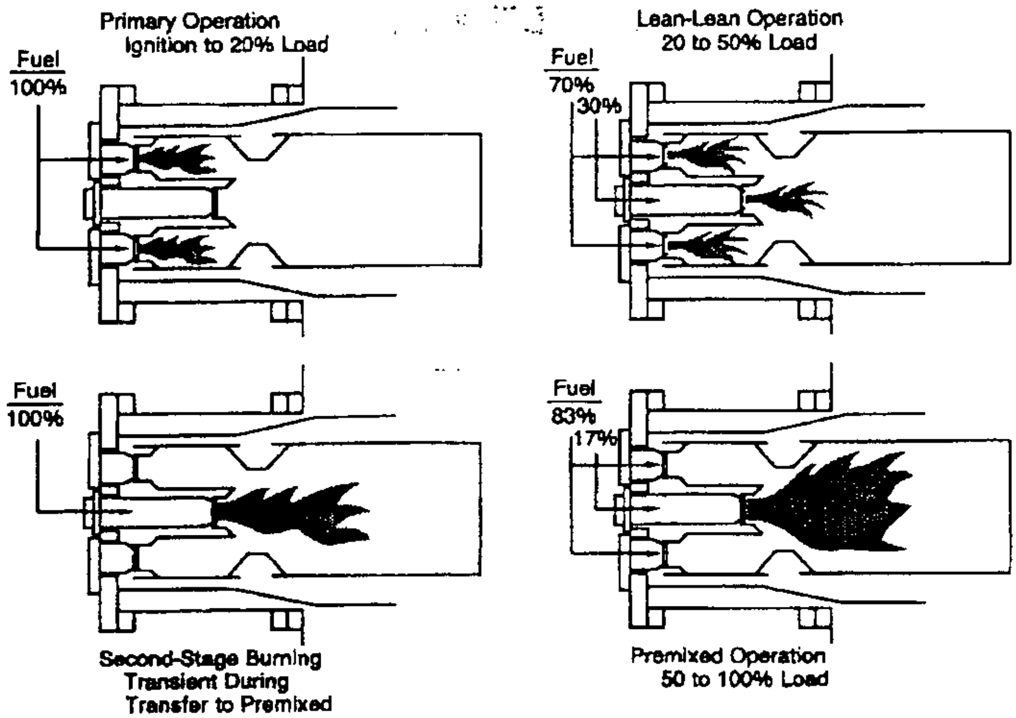
GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the Vandolah project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 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.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a 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 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.

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppmvd of CO. Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the Vandolah project are shown in Figure 4.

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.

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



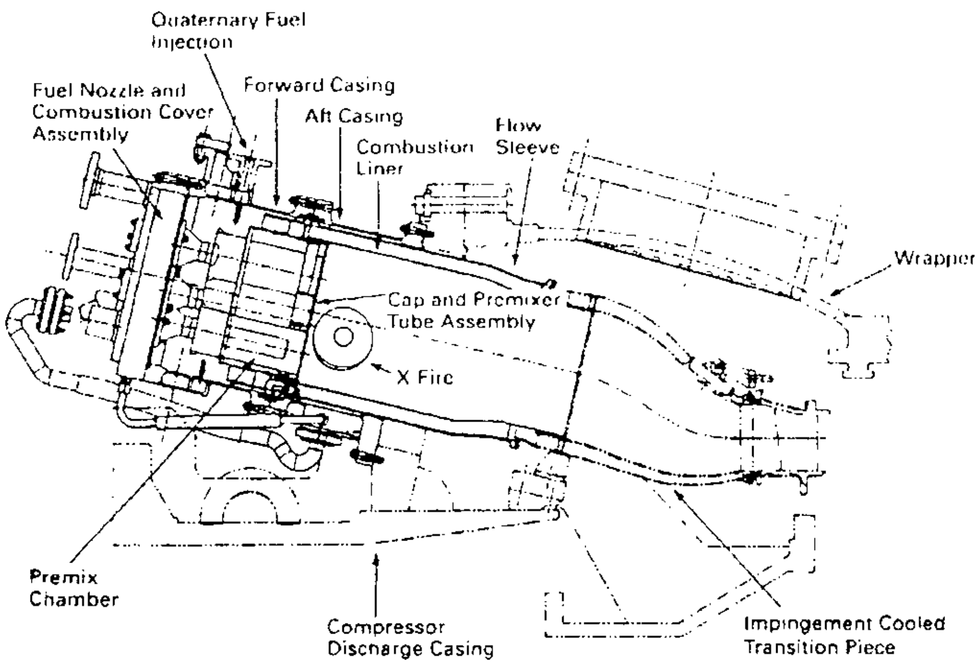


Figure 1 – Dry Low NO_X Operating Modes – DLN-1

Cross Section of GE DLN-2

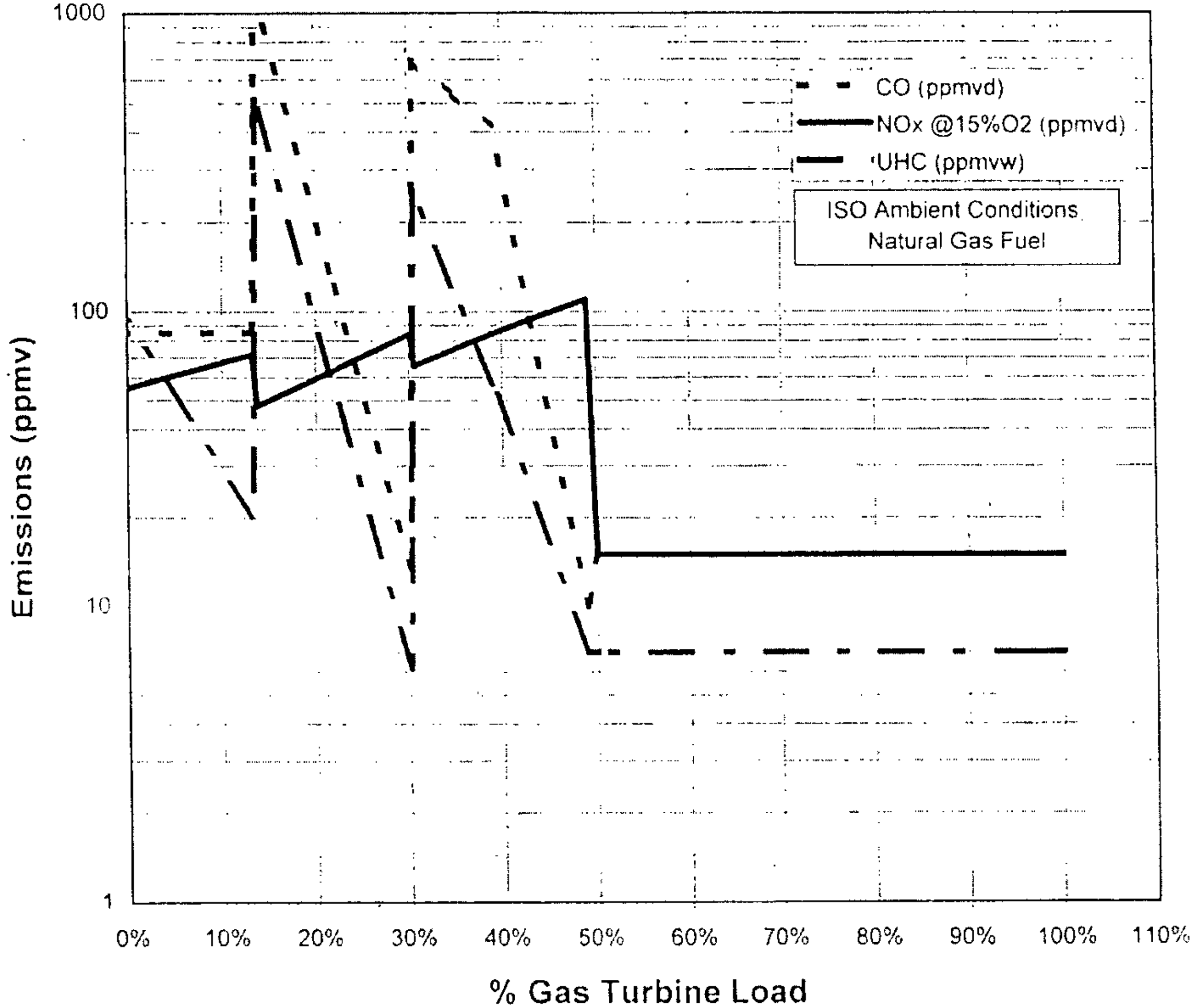


Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

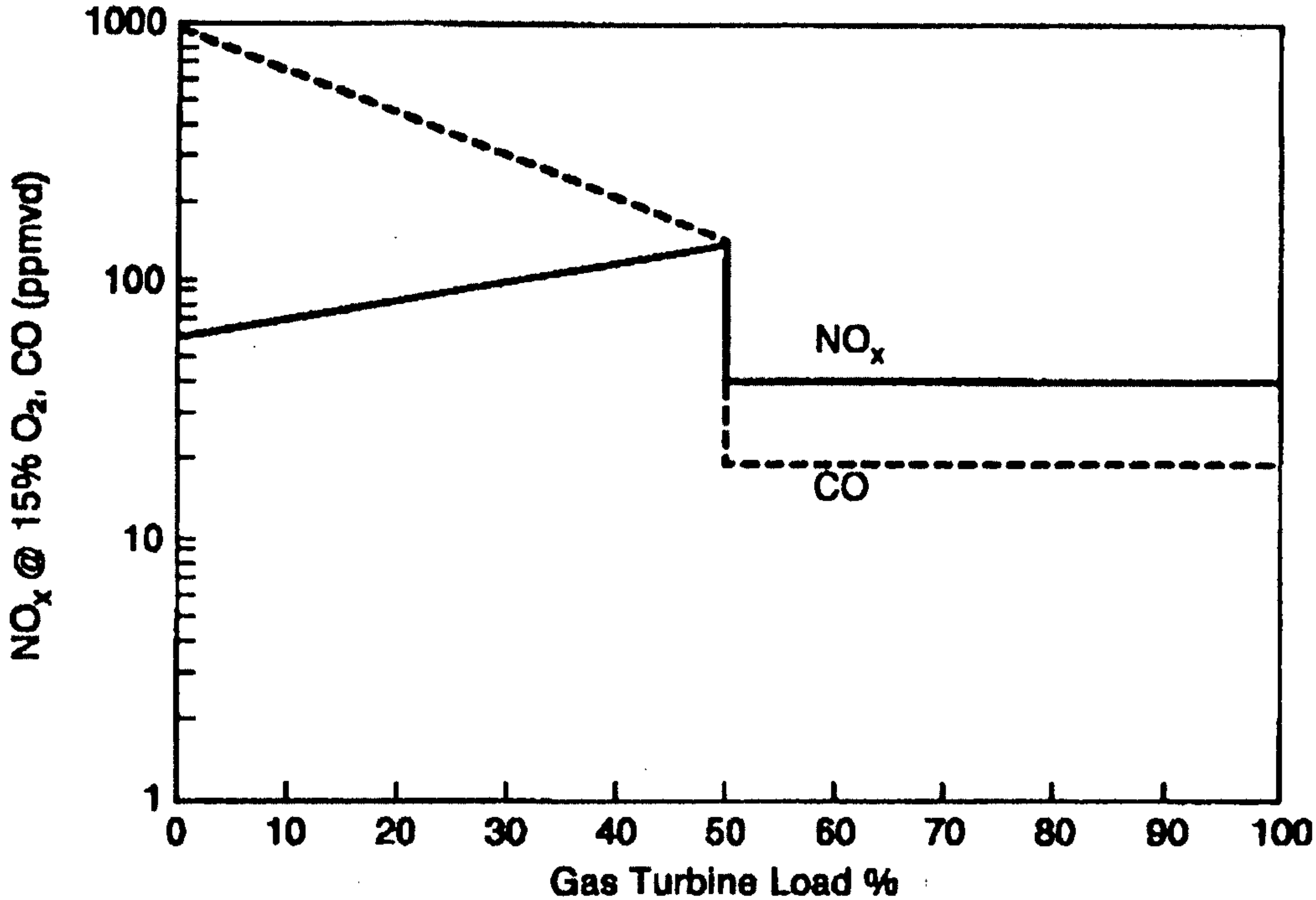


Figure 3 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

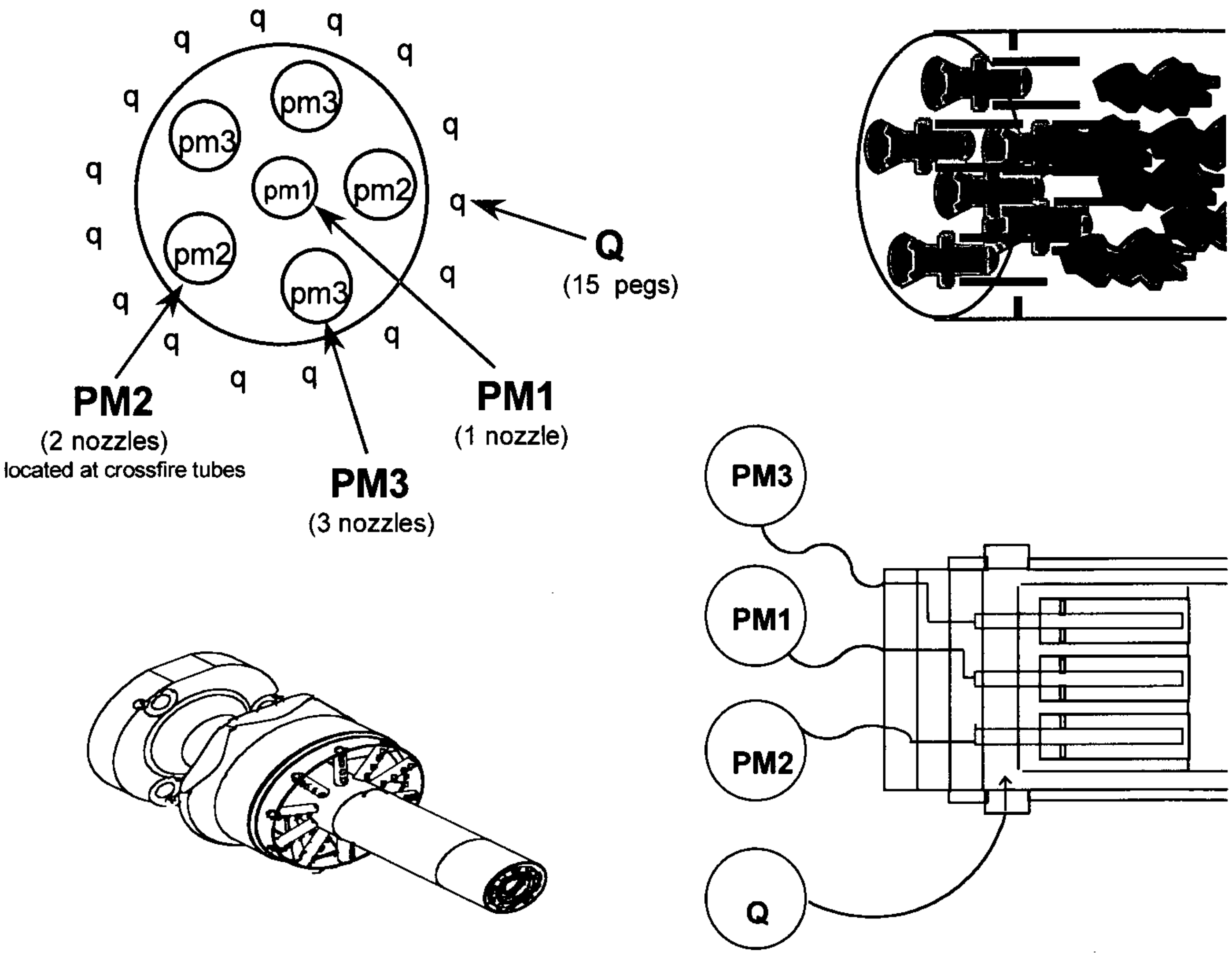


Figure 4 - DLN2.6 Fuel Nozzle Arrangement

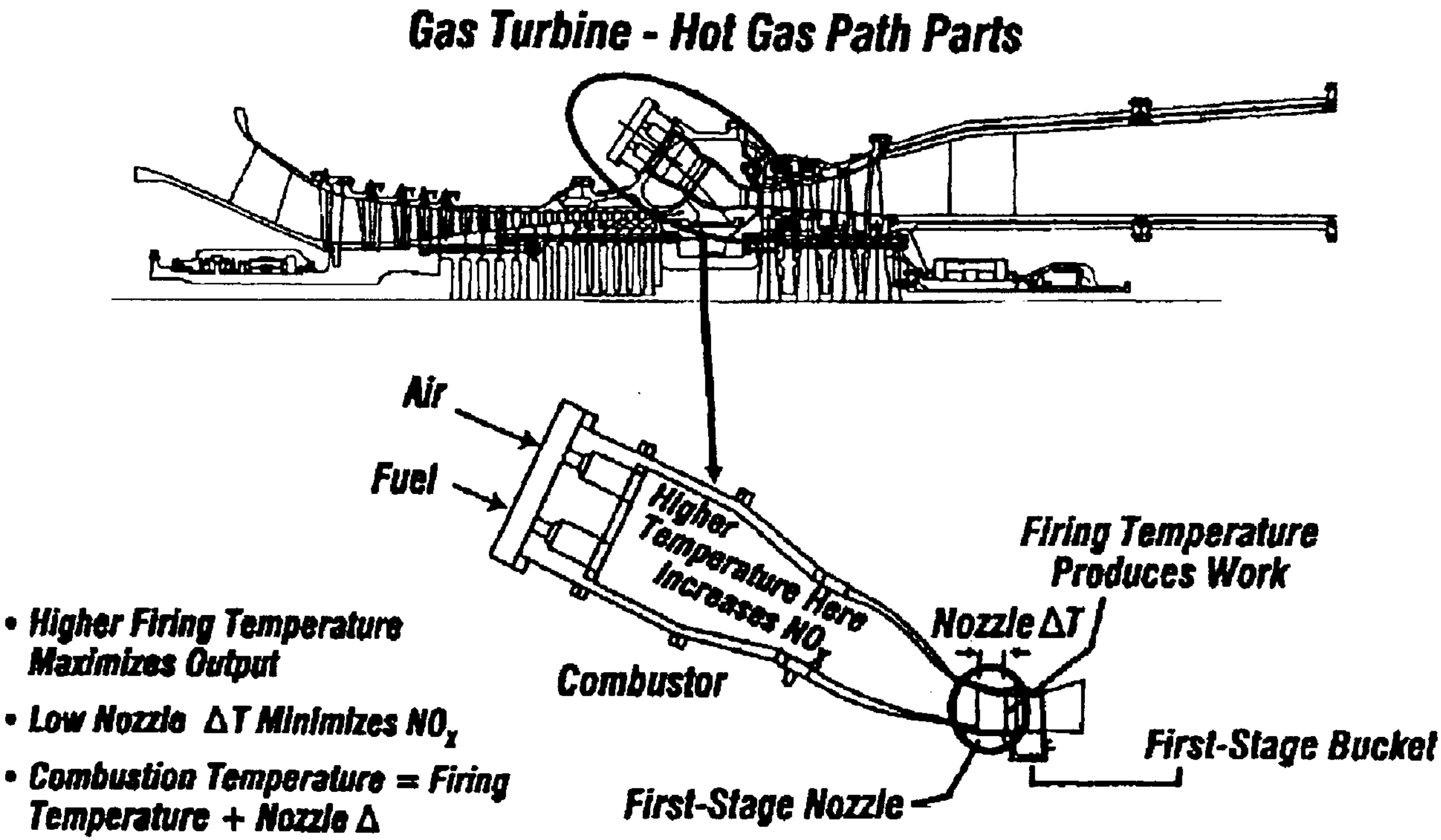


Figure 5 – Relation Between Flame Temperature and Firing Temperature

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

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[1], but their performance on fuel oil is not known to the Department.

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 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. The recently permitted Kissimmee Cane Island Unit 3 project is one example.[2]

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.

Emerging Technologies: $SCONO_X$™ and XONON™

$SCONO_X$™ is a catalytic 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 harmless 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.[3] 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.[4] The overall project includes several more 250 MW blocks with SCR for control.[5] 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.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the $SCONO_X$™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for $SCONO_X$™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before $SCONO_X$™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). On December 1, 1999, ABB Environmental recently announced that that it is offering the technology with performance guarantees to all owners and operators of natural gas combined cycle combustion turbines, regardless of size. $SCONO_X$ 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.

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. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

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 221 TPY of SO_2 and 34 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 1 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 82 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 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. 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.[6]

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 12 and 20 ppmvd for gas and oil respectively at baseload proposed in IPSAPC'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 IPSAPC for this project are 1.4 ppmvd for gas and 7 ppmvw for oil firing at baseload. According to GE, however, VOC emissions less than 1.4 ppmvd were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[7]

BACKGROUND ON PROPOSED GAS TURBINE

IPSAPC plans the purchase of four 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F (or 7FA) unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[8] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[9] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppmvd of CO, and 0-0.17 ppmvd of VOC.[10] The City of Tallahassee received a permit in 1998 to install a GE PG7231FA combustion turbine at its Purdom Plant.[11] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[12]

FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for fourteen GE 7241FA turbines to be installed at the Fort Myers and Sanford Repowering Projects.[13, 14] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241FA turbine with DLN-2.6 burners.[15] Draft BACT determinations of 9 ppmvd were proposed for the proposed combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities).[16, 17]

Most recently, the Department issued BACT determinations for the simple cycle Oleander project in Brevard County, the TEC project in Polk County, and the JEA Brady Branch Project in Duval. These three permits include "new and clean" NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units. The Oleander Project will meet 9 ppmvd on a 24-hour basis and will be allowed to burn fuel oil for 1000 hr/yr/unit. The TEC and JEA projects (as well as the proposed Reliant project in Osceola County) will meet 10.5 ppmvd on a 24-hour basis, but will limited in oil firing to 750 hr/yr/unit.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combustion turbines in Florida. When required by BACT determinations of most states, General Electric incorporates SCR in combined cycle projects.[18] In its recent permits, Florida has included separate and lower limits in the event that GE's DLN technology does not achieve 9 ppmvd or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[19] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 7-10 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[20] Unit 2 is equipped with DLN-1 combustors. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[21]

The 9-ppmvd NO_X limit on natural gas proposed by IPSAPC is very stringent for simple cycle 7FA combustion turbines. Typically, companies obtain a guarantee from GE to achieve 9 ppmvd 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 unit, some applicants, such as TEC, JEA, and Reliant are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, these companies agreed to a "new and clean" limit of 9 ppmvd but a continuing limit of 10.5 ppmvd. Their permits reflect fewer hours on oil for the higher NO_X value on gas. Presumably, their concern would be lessened should these units be converted to baseload combined cycle operation. Although the Department is not fully aware of the details of the GE guarantee for Vandolah (proposed 9 ppmvd on a simple cycle unit), the Department is aware from discussions with other applicants that a continuing guarantee may be available at a substantial cost.[22]

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.[23]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Vandolah project assuming full load. Values for NO_X 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
CO	As Above	12 ppmvd – Gas 20 ppmvd – Fuel Oil
VOC	As Above	1.4 ppmvd – Gas 7 ppmvw – Fuel Oil
SO_2/SAM	As Above	1 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 3,390 hours

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 and possibly less.
- An example of the above is the Carson Plant in Sacramento, California where there is an SCR system on a simple cycle LM6000PA combustion turbine. Emissions of ammonia are more than 10 ppmvd at the Carson Plant.

- Hot SCR is not commonly used on simple cycle combustion turbines and rarely in non-attainment areas. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. This does not mean that it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas.
- 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 ammonia slip guarantee is 10 ppmvd.
- The levelized costs of NO_X removal by Hot SCR for the Vandolah project were estimated by Golder at $14,900 per ton assuming 3,390 hours of operation on natural gas and a reduction from 9 to 3.6 ppmvd on gas and 42 to 17 ppmvd on fuel oil. The estimate is based on an ammonia slip of 10 ppmvd.
- The Department believes that the cost of NO_X control estimated for the Vandolah project is on the "high side." This is partly based on EPA Region IV comments on the Vandolah Power Project.[24] Also certain repetitive costs such as Engineering within Indirect Costs for three units are not likely to be three times as much as they are for a single units.
- In the face of a real requirement to install Hot SCR, a system could be engineered to cool the gases and use the heat in a recuperator of some kind. Additionally a once-through steam generator could accomplish the same end with the generated steam used for steam augmentation. This could increase revenues to pay for the additional equipment and possibly reduce the cost-effectiveness values.
- The Department believes, nevertheless, that the cost effectiveness of NO_X control by Hot SCR is still more than $10,000 per ton of NO_X removed.
- Hot SCR is not commonly used in PSD attainment areas. Although the Department does not have a "bright line" cost-effectiveness figure and does not necessarily adopt the precise cost calculations for the Vandolah project, Hot SCR is not cost-effective for this project. Therefore it is rejected as BACT.
- The Department will limit operation of the three units to 3,390 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, which 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 not available for F Class dual fuel projects.
- 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.
- 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. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.

- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A long-term limit of 9 ppmvd is required for the for five GE7 FA units in the Oleander Project in Brevard County and proposed for three identical units in the IPSAPC Shady Hills Project in Pasco County. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, and Virginia Power 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 while firing fuel oil 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 short period during start-up when emissions will actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into a mass emissions limit with a long-term averaging time for a continuous duty unit. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion.
- 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 issued or proposed 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 and Shady Hills.
- The proposed BACT limit of 9 ppmvd is about 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.[25]
- 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.

- It is possible that the NO_X emissions while firing oil from may be reduced from 42 ppmvd by increasing the water injection rate. 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'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.
- VOC emissions of 1.4 ppmvd while firing gas and 7 ppmvw while firing fuel oil proposed by the applicant clearly reflect BACT.
- The Department will set CO limits achievable by good combustion at full load as 12 ppmvd (gas) and 20 ppmvd (oil). These values are equal to the lowest values from permitted or proposed simple cycle units. These limits are equal to those proposed or approved by the Department for the Oleander, Shady Hills, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- Golder evaluated the use of an oxidation catalyst for the Vandolah project with an 80 percent control efficiency. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,700,000 per unit with an annualized cost of $466,000 per year per unit. Golder estimated levelized costs for CO catalyst control at $9,000 per ton. The Department does not necessarily adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- 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 PM10 will be set at 10 pounds per hour during gas operation and 17 pounds per hour while operating on fuel oil.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 1000 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. 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 and quite a number of combined cycle projects.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
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

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator A A L 12/15
New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

Date: 12/15/99

Approved By:

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

Date: 12/15/98

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

REFERENCES

1 Telecom. Linero, A.A., FDEP and Chalfin, J., GE. NO_X control technology for fuel oil.

2 Permit. Florida DEP. Kissimmee Utility Authority Cane Island Unit 3. File PSD-FL-254. November, 1999.

3 News Release. Goaline Environmental. Genetics Institute Buys $SCONO_X$ Clean Air System. August 20, 1999.

4 "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

5 Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

6 Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

7 Telecon. Vandervort, C., GE, and Linero, A.A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."

8 Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.

9 Davis, L.B., GE. "Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines." 1994.

10 Report. Florida Power & Light. "Final Dry Low NO_X Verification Testing at Martin Combine Cycle Plant." August 7, 1995.

11 Permit. Florida DEP. City of Tallahassee Purdom Unit 8. File PSD-FL-239. May, 1998.

12 Application. City of Tallahassee. PSD/Site Certification Application. April, 1997.

13 Permit. Florida DEP. FPL Fort Myers Repowering Project. File 0710002-004-AC. November, 1998.

14 Permit. Florida DEP. FPL Sanford Repowering Project. File 1270009-004-AC. September, 1998.

15 Permit. Florida DEP. Santa Rosa Energy Center. File 1130168-001-AC. December, 1998.

16 Draft Permit. Florida DEP. Duke Energy New Smyrna Project. File PSD-FL-257. January, 1999.

17 Draft Permit. Florida DEP. KUA Cane Island Unit 3. File PSD-FL-254. January, 1999.

18 Permit. State of Alabama. Alabama Power Plant Barry. 1998.

19 Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program

20 Monthly Report. Florida DEP Bureau of Air Regulation. June, 1998.

21 Telecon. Schorr, M., GE, and Linero, A.A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.

22 Telecon. Gianazza, N.B., JEA, and Linero, A.A., Florida DEP. Proposed NO_X limits at Brandy Branch Project.

23 Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."

24 Letter. Neeley, R.D., EPA Region IV to Linero, A.A., FDEP. Draft Permit for IPS Avon Park Vandolah Power Project. November 19, 1999.

25 Letter. Linero, A. A., FDEP to Forry, J. and Chalfin, J. General Electric. NO_X emissions control while firing fuel oil in Simple Cycle Units. October 12, 1999.

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 L Rhodes

~~TO:~~ Thru: Clair Fancy CHF

BAR

FROM: Al Linero AAL 12/14

DATE: December 14, 1999

SUBJECT: IPSAPC Vandolah Power Project
Four 170 MW Combustion Turbines
DEP File No. 0490043-001-AC (PSD-FL-275)

Attached is the Final Determination, Notice, Permit, and BACT for construction of four dual-fuel, intermittent duty, simple cycle, 170 MW combustion turbines and two 2.8 million gallon fuel oil storage tanks at the planned Vandolah Power Project near Wauchula in Hardee County.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6). The applicant proposed an NO_X emission limit of 9 ppmvd @15% O_2. The use of fuel oil will be allowed up to 1000 hours per year per unit. The NO_X and fuel oil hours are equal to the values in the Final Oleander permit. For reference, JEA and TEC were allowed 10.5 ppmvd NO_X on gas, but only 750 hours per year per unit of operation on fuel oil.

NO_X emissions will be controlled to 42 ppm during the limited fuel oil use. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

I recommend your approval and signature on the Permit and BACT determination.

AAL/al

Attachments