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May 3, 2002

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BUREAU OF AIR REGULATION

0137609

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

RE: FPL MARTIN EXPANSION PROJECT
Request for Additional Information
Project No. 085001-010-AC (PSD-FL-327)

Dear Jeff:

On behalf of Mr. John Lindsay of Florida Power & Light Company, I am submitting the enclosed responses to the comments and questions contained in your March 1, 2002 letter to Mr. Lindsay concerning the Air Permit and Prevention of Significant Deterioration (PSD) Application for the FPL Martin Expansion Project. The responses to your comments and questions have also been included in the sufficiency responses submitted to Mr. Over as part of the Site Certification proceedings.

Also included with these response is the initial compliance test results for Martin Units 8A and 8B when firing distillate oil. These tests were submitted previously to demonstrate compliance with emission limits.

We trust this responds fully to all of your comments and questions. Please contact either Mr. Simmons, the FPL application contact [phone (561) 691-2216], or myself if we may be of further assistance.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

KFK/lsh

Enclosures: 1 copy

cc: John M. Lindsay, Plant General Manager Martin Plant
K. H Simmons, Manager of New Capacity Projects

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Martin Expansion Project
Additional Information – FDEP New Source Review Section
Project No. 085001-010-AC (PSD-FL-327)

Comment 1a: "Equipment Description: Please verify and comment on the information in the following description of equipment: Combined Cycle Unit No. 8 will be a "4 on 1" unit consisting of four 170 MW gas turbines, four gas-fired heat recovery steam generators (HRSGs), and one steam turbine-electrical generator."

Response: Yes the statement is correct. The project will include a "4 on 1" unit consisting of four General Electric (GE) nominal 170 MW gas turbines, four heat recovery steam generators (HRSGs) with duct firing, one steam turbine-electrical generator and associated ancillary equipment. Two of the combustion turbines are existing simple cycle units. The project also includes the option of a mechanical draft cooling tower.

Comment 1b: "Gas Turbines: Each gas turbine (Unit Nos. 8A, 8B, 8C, and 8D) includes General Electric Model PG7241(FA) combustion turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a simple cycle exhaust stack that is 80 feet tall and 22.0 feet in diameter, fuel distribution systems, and ancillary support equipment. Exhaust gases will exit the simple cycle stack at approximately 1116°F with a volumetric flow rate of approximately 2,389,500 acfm."

Response: Yes, the statement is correct. Each gas turbine (Unit Nos. 8A, 8B, 8C, and 8D) includes a General Electric Model PG7241 (FA) combustion turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a simple cycle exhaust stack (that has been modeled at 80 feet tall and 22.0 feet in diameter), fuel distribution systems, and ancillary support equipment. Exhaust gases will exit the simple cycle stack at approximately 1116°F with a volumetric flow rate of approximately 2,389,500 acfm, based on an ambient (turbine inlet) temperature of 59° F.

Comment 1c: "Heat Recovery Steam Generators (HRSGs): During combined cycle operation, the exhaust from each gas turbine will pass through a separate gas-fired heat recovery steam generator with an exhaust stack that is 120 feet tall and 19.0 feet in diameter. Exhaust gases will exit the HRSG stack at approximately 202°F with a volumetric flow rate of approximately 1,004,000 acfm."

Response: Yes, the statement is correct. During combined cycle operation, the exhaust from each gas turbine will pass through a separate gas-fired heat recovery steam generator with an exhaust stack that is 120 feet tall and 19.0 feet in diameter. Exhaust gases will exit the HRSG stack at approximately 202°F with a volumetric flow rate of approximately 1,004,000 acfm, based on an ambient (turbine inlet) temperature of 59°F.

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Comment 1d: "Fuels and Firing Rates: The primary fuel for each gas turbine is natural gas with very low sulfur distillate oil (0.05 percent sulfur by weight) serving as a backup fuel on a restricted basis. At a compressor inlet air temperature of 59°F, the maximum heat input rate of each gas turbine is 1600 MMBtu (LHV) per hour when firing natural gas and 1811 MMBtu (LHV) per hour when firing distillate oil. Each HRSG is designed with duct burners having a maximum heat input of 550 MMBtu (LHV) per hour when firing natural gas."

Response: The statement is correct except that the each HRSG is designed with duct burners having a maximum heat input of 550 MMBtu per hour based on the higher heating value (HHV) and 495 MMBtu per hour based on the lower heating value (LHV). In addition, distillate oil is considered an "alternate" fuel that may be used on a restricted basis.

Comment 1e: "Generating Capacity: At a compressor inlet air temperature of 59°F and the maximum heat input rate, each gas turbine generates a nominal 172 MW of shaft-driven electricity when firing natural gas and 180 MW of shaft-driven electricity when firing distillate oil. The single steam-turbine electrical generator is rated at a capacity of 470 MW. With all four gas turbines in operation and firing all HRSG duct burners, the combined cycle system generates a nominal 1150 MW of electricity."

Response: Yes, the statement is correct. At a compressor inlet air temperature of 59°F and the maximum heat input rate, each gas turbine generates a nominal 172 MW of shaft-driven electricity when firing natural gas and nominal 180 MW of shaft-driven electricity when firing distillate oil. The single steam-turbine electrical generator is rated at a nominal capacity of 470 MW. With all four gas turbines in operation and firing all HRSG duct burners, the combined cycle system generates a nominal 1150 MW of electricity.

Comment 1f: "Controls: Each gas turbine incorporates General Electric's dry low-NO_x combustion system (2.6) to minimize the formation of NO_x emissions when firing natural gas. A water injection system will be installed to minimize NO_x emissions when firing distillate oil. A conventional selective catalytic reduction (SCR) system will be installed in the HRSG to further reduce NO_x emissions during combined cycle operation. The efficient combustion of very low sulfur fuels at high temperatures minimizes the emissions of CO, PM/PM_{10}, SO_2 and VOC."

Response: Yes, the statement is correct. Each gas turbine incorporates General Electric's dry low-NO_x combustion system (2.6) to minimize the formation of NO_x emissions when firing natural gas. A water injection system will be installed to minimize NO_x emissions when firing distillate oil. A conventional selective catalytic reduction (SCR) system will be installed in the HRSG to further reduce NO_x emissions during combined cycle operation. The efficient combustion of very low sulfur fuels at high temperatures minimizes the emissions of CO, PM/PM_{10}, SO_2 and VOC.

Comment 1g: "Continuous Monitors: Each gas turbine will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NO_x emissions as well as flue gas carbon dioxide content."

Response: Yes, the statement is correct except either carbon dioxide or oxygen, as the diluent gas for nitrogen oxides will be selected. Each gas turbine will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NO_x emissions.

Comment 2: "Fuel Heaters: Please describe when fuel heating is necessary. Why will the gas-fired fuel heaters operate more during the first year of operation? Why aren't the fuel heaters necessary during combined cycle operation? Is there a separate heat transfer system used during combined cycle operation?"

Response: The GE 7FA combustion turbine is available with two types of DLN combustors that fire natural gas. The first type is called a "cold" nozzle and the second type is a "hot" nozzle. FPL uses the hot nozzle design because it uses hot fuel (290-365°F), which is heated using waste energy from the combustion turbine exhaust via a feed water heat exchanger. This improves the overall plant efficiency. The hot nozzles require a temperature of the natural gas to be 290°F when at a minimum continuous load of (30 MW). The energy to heat the fuel from a feed water heater is not available in simple cycle mode since there is no steam cycle and is not available during initial start up. The energy to heat the natural gas during these conditions must be supplied from another source, which is a direct fired gas heater. The direct fired gas heaters are used in simple cycle mode and may be used during the first 30 to 60 minutes of startup in combined cycle mode. In full combined cycle mode the fuel heaters are not required since waste heat from a feed water heater is used. For the first year of operation in simple cycle mode and during the plant start up phases, there will be times when the fuel gas heaters will be required to operate.

Comment 3: "Cooling Tower: Please identify the determining factors in whether or not the proposed cooling tower will be installed."

Response: The primary determining factor in whether or not the proposed cooling tower will be installed are construction considerations. With regards to construction, FPL is further investigating various construction techniques in order to minimize the costs associated with the installation of intake and outfall structures, including circulating water pipe sized to accommodate a once through cooling system. One alternative being the construction of a cooling tower which would be capable of using the existing Units 3 and 4 Intake and Outfall structures and associated circulating water piping.

Comment 4: "Fuel Oil Tanks: The application indicates that the combined capacity of both fuel tanks will be approximately 2 million gallons. Based on the maximum firing rate of 14,000 gallons per hour per gas turbine, the tanks would only provide about 36 hours of simultaneous operation of all four units. Approximately how many truckloads of oil will it take to fill the two tanks? Approximately how long will it take to empty one truckload of oil? How long will it take to refill the tanks? Are there adequate roadways to provide access for this number of trucks? Describe how oil would be delivered and transferred to the tanks when the units were in operation and were expected to fire oil for an extended period of time, such as several days."

Response: Chapter 3, page 3-5 of the application describes the light oil storage facilities of the project, "light oil will be stored in the existing 2-million-gallon tank and in a 2-million-gallon tank authorized in the 1991 certification for Units 3 and 4 but not constructed." The total combined capacity of both fuel tanks will be approximately 4 million gallons. The existing 2-million gallon tank is currently being used for Units 8A and 8B. Based on the maximum firing rate of 13,900 gallons per hour per CT, the tanks would provide about 72 hours of simultaneous operation in the event all four units were fired at full load. Each 2-million-gallon tank will require about 270 truckloads at a nominal capacity of 7,500 gallons per standard tanker truck. At 13,900 gallons per hour it will take each CT about 32 minutes to burn the amount of distillate oil in a standard tanker. The facility has the ability to off-load two standard oil tankers at a time and a rate of 50,400 gallons per hour. Since oil will not be the primary fuel, the filling of each tank will be scheduled over a period of time. A traffic analysis was performed for both construction and operation and was presented in Chapters 4 and 5 of the Site Certification Application. The most traffic occurs during construction when several hundred construction workers will come to and exit the site. The traffic analysis determined under worst case construction traffic that the roads would operate at an acceptable level of service (Section 4.6.1 of SCA).

Comment 5a: "Operational Restrictions Requested: Please comment on the Department's interpretation of the following restrictions requested in the application.

Each gas turbine shall fire no more than 500 hours of oil per consecutive 12 months (or equivalent oil consumption at full load).

- Because of higher emissions of nearly all pollutants when firing oil, the Department has restricted oil firing as part of its BACT determination for several recent projects. For similar projects, the Department has restricted oil firing to no more than 250 hours per year per gas turbine at full load. Please comment.
- The Department will consider this restricted operation in terms of hours of operation or fuel consumption (gallons). Please identify the preferred restriction in these terms."

Response: FPL has requested a fuel equivalent of 500 hours of light oil operation per consecutive 12 months per CT. The amount of light oil firing requested in the application is a project specific requirement. The existing Unit 8A and 8B CTs are currently permitted a fuel equivalent of 500 hours/CT/year [i.e., 7,358,350 gallons; see PSD-FL-286, Section III, Condition 8(6)]. FPL's operational requirements dictate that the new Unit 8 CT oil firing limitations match that of the existing CTs.

While it is acknowledged that the Department recently permitted projects with 250 hours of light oil firing, FDEP has also proposed permits for recent projects with 500 hours of light oil operation per consecutive 12 months per CT, e.g., South Pond Energy Park, LLC (draft permit dated in November, 2001). South Pond Energy Park, LLC is a 600 MW electrical generating plant in Hardee County, FL, consisting three GE 7FA units. In addition, unlike independent power projects that the Department has recently permitted, FPL has a statutory obligation to supply electric power at all times. Having the ability to use light distillate oil for an equivalent of 500 hours per CT provides the reliability to meet this obligation.

The preferred restriction for limiting light oil firing operation is in terms of fuel consumption (gallons): "The maximum annual usage for the four CTs is 29,433,400 gallons." Calculation: 7,358,350 gallons/CT x 4 CTs = 29,433,400 gallons.

Comment 5b: "Duct firing shall not exceed an equivalent of 2880 hours per year per HRSG at full capacity.

Please identify the requested restriction in terms of maximum hours of operation or gas consumption (million cubic feet of gas)."

Response: The preferred restriction for limiting duct firing is in terms of gas consumption. Based on 2880 hr/yr/HRSG and 550 MMBtu/hr/HRSG, the maximum fuel consumption is calculated to be 274 million lb/year or 6 billion scf/year for all four HRSGs.

Comment 5c: "Each gas turbine shall be limited to no more than 400 hours per consecutive 12 months of steam injection for power augmentation."

Response: Yes, the statement is correct. The application requests that each gas turbine be limited to no more than 400 hours per consecutive 12 months of steam injection for power augmentation. This restriction is the same as the current permit limitation of the existing Units 8A and 8B CTs.

Comment 5d: "Each gas turbine shall be limited to no more than 60 hours per consecutive 12 months of high temperature peaking operation."

Response: Yes, the statement is correct for simple cycle operation. The application request that each gas turbine be limited to no more than 60 hours per consecutive 12 months of high temperature peaking operation. This restriction is the same as the current permit limitation of the existing Unit 8 CTs. For combined cycle operation, the peak mode, which was characterized as the "Higher Power Mode" and included steam augmentation, a 400 hours per consecutive 12 month is requested.

Comment 5e: "Excluding startup and shutdown, each gas turbine shall not operate below 50 percent of base load."

Response: FPL requests that operation not be limited by load, but rather compliance with emission limits. During the construction of combined cycle, operating the CTs at less than 50 percent load will be required for extended periods to accomplish steam blows. A permit condition to accomplish this was included in the application (refer to Section 2.0). In addition, some maintenance conditions and operational circumstances may require operation at less than 50 percent load.

Comment 5f: "Until capable of operating in combined cycle mode, each gas turbine shall operate no more than 3390 hours per consecutive 12 months."

Response: Yes, until capable of operating in combined cycle mode, each gas turbine shall operate no more than a fuel equivalent of 3,390 hours per consecutive 12 months or 5,902,588,000 SCF of gas per turbine. The existing Units 8A and 8B CTs are limited on this basis [see PSD-FL-286, Section III, Condition 8(a)]. If oil is used, the natural gas limit would be reduced by 127.4 SCF of gas for every gallon of distillate oil used.

Comment 5g: "Once combined cycle operation is established, simple cycle operation of the four gas turbines shall not exceed an average of 1000 hours per consecutive 12 months. Operation of any simple cycle operation shall not exceed 3390 hours per consecutive 12 months."

Response: Yes, once combined cycle operation is commenced, simple cycle operation of the four gas turbines shall not exceed an average of fuel equivalent of 1,000 hours per consecutive 12 months (1,741,176,400 SCF of gas per turbine). Operation of any simple cycle operation shall not exceed a fuel equivalent of 3,390 hours per consecutive 12 months. The requested condition would be on the same basis as the current limitation for Units 8A and 8B (see response to comment 6p).

Comment 5h: "Please explain the requested "aggregate" limit for simple cycle operation and oil firing after the combined cycle unit begins operation."

Response: During simple cycle operation the requested "aggregate" limit means that the maximum total combined hours of oil firing operation of the four CTs will not exceed a fuel equivalent of 2,000 hours. Each CT may operate in oil firing mode for a fuel equivalent of 500 hours per consecutive 12-month period or any combination of CT operating hours that is equivalent to 29,433,400 gallons; for example, if one CT uses 14,716,700 gallons (i.e. ½ of the aggregate limit), then the other three can only use 14,716,700 gallons or 4,905,566 gallons per CT.

Comment 5i: "Note that all requested annual limits will be specified in terms of 'consecutive 12 months'."

Response: The statement is acknowledged.

Comment 6a: "Emissions

Please provide General Electric's emissions data sheets for gas firing and oil firing including standard operation, power augmentation, and high temperature peaking at a compressor inlet air temperature of 59°F and 100-percent load."

Response: See Attachment A for GE data sheets for Units 8A and 8B. Units 8C and 8D will be similar.

Comment 6b: "Please provide the manufacturer's emissions data sheet for the duct burners. Provide supporting documents and/or calculations of the expected emission levels for the combined gas turbine exhaust and the duct burner emissions (CO, NO_x, and VOC)."

Response: The manufacturer of the duct burners has not been selected. The duct burner emissions presented in the application have been guaranteed on other similar projects. Attachment B presents typical information from duct burner manufacturers.

Comment 6c: "The proposed NO_x BACT emission rate of 12.0 ppmvd at 15-percent O_2 when firing oil in combined cycle mode is higher than recent Department permits, which have established a BACT limit of 10.0 ppmvd at 15-percent O_2 for an identical gas turbine controlled by SCR. Please comment."

Response: The NOx emission limit proposed for the turbines proposed for combined cycle operation when firing fuel oil and operating in combined cycle mode is 12 ppmvd at 15-percent O_2. This proposed NO_x emission limit balances the cost of the SCR system when designed for

2.5 ppmvd when firing natural gas. A lower limit for distillate will shift the design of the SCR system based on the oil limit. This increases the cost unnecessarily since oil is the alternate fuel.

Comment 6d: "The proposed NO_x BACT emission rate of 42.0 ppmvd at 15-percent O_2 when firing oil in simple cycle mode is higher than recent Department permits, which have established BACT limits as low as 36.0 ppmvd at 15-percent O_2 for an identical gas turbine controlled by wet injection. Please comment."

Response: The GE NO_x emission guarantee for the turbines proposed for the project when firing fuel oil and operating in simple cycle mode is 42 ppmvd at 15-percent O_2. The Department permitted Units 8A and 8B at this GE guaranteed limit when firing oil. The emission test report for Units 8A and 8B are being submitted to the commenter separately.

Comment 6e: "Please clarify the averaging period for the requested NO_x limit (3-hour or 24-hour; see page 2-4 and Table 4-1)."

Response: The footnote in Table 4-1 on page 2-4 of the application was incorrect. The requested averaging period for the NO_x limit is a 24-hour period as stated in Table 4-1 and included in the Emission Unit section of the application form.

Comment 6f: "General Electric has guaranteed CO emission rates of 7.4 and 14.4 ppmvd at 15-percent O_2 for gas and oil firing for the Frame 7FA gas turbine. Please explain the proposed CO BACT emission rates of 9 and 20 ppmvd at 15-percent O_2."

Response: The proposed CO BACT emission rates for CO are 9 and 20 ppmvd, not corrected to 15-percent O_2. The above mentioned 7.4 and 14.4 ppmvd at 15-percent O_2 emission rates are equivalent to the proposed 9 and 20 ppmvd. GE provides CO emission guarantees based on ppmvd and not corrected to 15-percent O_2, therefore the proposed emissions provided in the application are in units of ppmvd. The current CO limits for Units 8A and 8B are expressed in ppmvd.

Comment 6g: "The requested CO BACT emission rates of 24.5 ppmvd at 15-percent O_2 (gas firing with duct burning), 29.5 ppmvd at 15-percent O_2 (gas firing with duct burning and power augmentation or peaking), and 20.0 ppmvd at 15-percent O_2 (oil firing) do not represent current BACT levels of control for CO emissions. At these levels, the Department believes that an oxidation catalyst may be cost effective. Please comment."

Response: The requested CO BACT emission rates are in units of ppmvd not corrected to 15-percent O_2. The corresponding values of the requested CO emission rates in units of ppmvd at 15-percent O_2 are as follows:

- 14.7 ppmvd at 15-percent O_2 (gas firing with duct burning)
- 19.2 ppmvd at 15-percent O_2 (gas firing with duct burning and power augmentation or peaking)
- 14.1 ppmvd at 15-percent O_2 (oil firing)

Please refer to Tables A-2 and A-10 of the PSD Application (Appendix 10.1.5 of the SCA). Since GE provides CO emission guarantees based on ppmvd and not corrected to 15-percent O_2, the proposed emissions provided in the application are in units of ppmvd when duct firing. CO emission limits for other similarly large combined cycle projects (i.e., >500 MW) ranged from 16 ppmvd at 15-percent O_2 for the Hines Energy Complex to 17 ppmvd at 15-percent O_2 for the Osprey Energy Center. Both limits were 24-hour block averages.

The addition of an oxidation catalyst is not considered appropriate nor cost effective, given the "insignificant" ambient air impacts, collateral environmental effects and cost effectiveness. The cost effectiveness was estimated to be $4,165 per ton of CO removed. This also assumed maximum worst-case emissions, which is extremely conservative given the actual performance of the GE Frame 7FA as acknowledged by the department in recent permits. Moreover, there is no secondary environmental benefits of an oxidation catalyst since the amount of backpressure and lost energy ultimately results in the generation of more CO_2 than is being controlled in the oxidation catalyst (refer to Tables B-10 and B-11 in Appendix B of the Air Permit/PSD Application; Appendix 10.1.5 of the SCA).

Comment 6h: "Please provide supporting documentation that duct burning would increase CO emissions from 7.4 ppmvd at 15-percent O_2 to 24.5 ppmvd at 15-percent O_2 when firing natural gas. Verify that high temperature peaking would not increase CO emissions. Provide supporting documentation that duct burning with power augmentation would increase CO emissions from 24.5 ppmvd at 15-percent O_2 to 29.5 ppmvd at 15-percent O_2 when firing natural gas."

Response: This information was presented in Appendix A of the PSD Application (Appendix 10.1.5 of the SCA).

CO (lb/hr) = CO (ppm) x [1 - Moisture (percent)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp. (°F) + 460°F) x 1,000,000 (adj. for ppm)]

A. At an ambient temperature of 95° F, given the CT CO emission rate of 25.5 lb/hr based on the GE guarantee, and the duct burner (DB) CO emission rate of

0.08 lb/MMBtu and a heat input of 550 MMBtu/hr, the CT/DB emission rate is equivalent to 69.5 lb/hr. For this operating case, the moisture, temperature are as follows: 12.17 percent, 1143°F.

See Attachment C for the calculation of the volume flow rate for the CT and DB equal to 2,277,437 acfm.

The resulting CO ppmvd emission concentration equals 24.5 ppmvd or 14.7 ppmvd at 15-percent O_2.

B. At an ambient temperature of 80° F and operation in power augmentation, given the CT CO emission rate of 45 lb/hr based on the GE guarantee, and the duct burner (DB) CO emission rate of 0.08 lb/MMBtu and a heat input of 550 MMBtu/hr, the CT/DB emission rate is equivalent to 89 lb/hr. For this operating case, the moisture, temperature are as follows: 19.2 percent, 1125°F.

See Attachment C for the calculation of the volume flow rate for the CT and DB equal to 2,403,989 acfm.

The resulting CO ppmvd emission concentration equals 29.5 ppmvd or 19.2 ppmvd at 15-percent O_2.

Comment 6i: "The application requests EPA Method 10 testing to demonstrate compliance with the CO standards. Based on recent PSD permits for identical units, the Department intends to require a CO CEMS. Please comment. "

Response: The inclusion of continuous emission monitoring (CEM) for CO is not warranted based on performance of the turbines as well as the need relative to environmental considerations. The BACT analysis suggests that such CEM systems are not required given the "insignificant" ambient impact.

Comment 6j: "Please provide supporting documentation that duct burning would increase VOC emissions from 3.5 ppmvw to 7.0 ppmvw (when firing oil in the gas turbine)."

Response: Duct burners will not be fired during CT operation with light fuel oil. Based on GE guarantee data, the VOC emissions during light fuel oil firing will be 3.5 ppmvw. Duct burners will be fired only during natural gas operation of the CTs. The maximum VOC emission concentration during CT and duct burner firing will be 7.0 ppmvw. See Table A-2 of Appendix A in the Air Permit/PSD Application; Appendix 10.1.5 of the SCA.

Comment 6k: "The proposed visible emissions standard of 20-percent opacity when firing oil is inconsistent with recent Department permits for identical units, which limit opacity to 10 percent for all fuels. Please comment."

Response: An opacity limit of 10 percent is acceptable for the Project when firing natural gas or light distillate oil.

Comment 7a: "Excess Emissions: Please describe the 'steam blow' process and explain why 90 days of steam blows are necessary at the beginning of operation for this project."

Response: During construction, the steam piping systems internally accumulate weld spatter, slag, filings, and other debris. If this material is not removed prior to steam turbine operation, the steam turbine will be damaged by the metal particles, which would strike the blades and steam path vaning at very high velocities. Blowing through the piping system with steam removes this material, along with rust, grease, and other fabrication and construction residues prior to commencement of combined cycle operation.

The steam blow procedure involves firing the combustion turbine (CT) in order to generate steam in the heat recovery steam generator (HRSG), and then passing the steam through the piping towards the steam turbine. A temporary tee is installed in the steam line to divert the steam and foreign matter, to the atmosphere. Initial "steam blowing" is performed until the exhaust has no color, and then a polished target is inserted near the venting location, prior to subsequent blows. Blowing of steam through the line continues until the target shows limited "hits", according to an established criteria. When this criteria has been met, the line is considered clean. This method is used to clean the main high-pressure steam supply piping as well as the hot and cold reheat steam piping, steam bypass piping, and low pressure steam piping systems. These blows are carried out separately for each system, and in some cases, done in combination with other systems. Following the steam blow procedure of the four CT/HRSG sets, the steam blow procedure is done on the combined steam lines of the CT/HRSG to the main turbine.

The steam blow procedure is carried out at about 600 psi, which is less than the 2000 psi under normal operating conditions. This requires that the CT load be at less than 50 percent operating levels to supply the required steam. Further, it is desirable to thermally cycle the piping during the process, which requires CT shutdowns and restarts.

The 90-day period referenced for steam blow is the calendar duration from initiation of the process until completion for all four CT/HRSGs and mainstream lines to the steam turbine. The process will be intermittent throughout the 90-day period. There are numerous activities involved exclusive of the steam blow procedure. For example, temporary steam blow piping and valves must be removed and reinstalled for the various steam blowing operations. Occasionally, equipment repair or replacement is necessary; and there may be delays due to weather or other event. The duration of steam blowing is indeterminate but can be performed within the 90 day period requested.

Comment 7b: "Please describe the startup and shutdown procedures including the approximate lengths of time for each portion of the procedure (cold, warm, hot, simple cycle, and combined cycle)."

Response: In simple cycle operation, the CTs meet emission limits within about 30 minutes. In combined cycle, the startup of the combustion turbine involves controlling the exhaust temperature and flow, so as not to exceed limitations imposed by the HRSG manufacturer regarding rate of change of metal temperature change and metal temperature differentials. These limitations are reflected in maximum allowed increasing and decreasing HRSG ramp rates, and specified steam drum temperatures/pressures and durations.

The limitations result in the need for a relatively long startup time for the CT when the HRSG is cold. If the plant has been operating, and is then shutdown for more than 48 hours, the HRSG is considered to be cold. Then a 4-hour HRSG startup duration is required before the CT can be operated in at loads above 50 percent load when firing natural gas.

If the plant shut down is less than 48 hours, then the HRSG is considered to be warm, and a 2-hour HRSG startup duration is required before the CT can be operated at above 50-percent load when firing natural gas.

Similar startup limitations, imposed by the steam turbine manufacturer are designed into the turbine control system, and will apply when starting the steam turbine for combined cycle operation.

These limitations result in a total duration of 12 hours where loads of 50 percent will occur for the CTs. The CTs are started in sequence and the conditions of cold and warm startup would apply.

The startup will vary by the equipment vendors but presented below is a typical description of the process. During all startup conditions, the speed and load of the combustion turbines (CTs) are regulated to provide conditions that would not damage the HRSGs or steam turbine. The typical conditions described below.

1. Cold Start –Occurs when the combined cycle unit has been shutdown for more than 48 hours. The total time for this startup condition is 12 hours. The first CT is started and held at certain levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 2-hours into the start and load is applied to the CT at about 3 hours into the start. The second CT is started about 3 to 4 hours into the start with load applied at about 4 to 5 hours into the start. The third and fourth CTs are started in a similar sequence. At 12 hours into the start, all CTs are at a load that will comply with proposed emission limits.

2. Warm Start – Occurs when the combined cycle unit has been shutdown for 48 hours or less. The total time for this startup condition is about 2 hours. Similar to the cold start, the first CT is started and held at levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 1 hour into the start and load is applied to the CT at about shortly thereafter. The second CT is started about 1 hour into the start with load applied at about 1½ hours into the start. At two hours into the start, the first CT has reach full load with steam applied to the steam turbine. The other turbines are started in similar sequence.

Section 2.5.2 of the Air Permit/PSD Application (Appendix 10.1.5 of the SCA) proposed a condition for cold startup of Unit 8 that was identical to that previously approved by the department for the FPL Fort Myers Repowering Project.

Comment 7c: "What pollutants will be in 'excess' of an emissions standard, what are the expected levels, and what will be the expected duration? Please provide supporting documentation."

Response: The emissions in excess of the emission limits will be for the pollutants of NOx, CO and VOC. Emissions of PM and SO_2 are governed by primarily fuel quality. During steam blows, the CTs are operated at about at a load of about 12 MW, which is about 7-percent load. Based on GE estimates, the NOx emissions will be from 70 to 80 ppmvd corrected to 15-percent O_2. These emission rates will exceed the performance at 50-percent load and above. In addition, the SCR will not yet be installed and the operating temperature will not be sufficient. For CO and VOC the estimated emissions will be 100 ppmvd and 7 ppmvw, respectively.

During cold and warm starts the NOx emissions will vary between about 60 and 100 ppmvd corrected to 15-percent O_2. For CO emission will be highly variable any range between 20 and 1,000 ppmvd. Similarly, VOCs will vary between less than 2 ppmvd and 100 ppmvd.

Comment 8a: "SCR Costs

It appears that Tables B-3a and B-4a regarding hot SCR costs have been inadvertently omitted from the application. Please submit."

Response: These tables were inadvertently omitted and are provided as Attachment D.

Comment 8b: "Based on a report prepared for the Department of Energy (Onsite Sycom, 11/99), the hot SCR costs appear to be much higher than expected. This report indicates that annualized costs for "hot SCR" for a large frame unit would be approximately 20 percent higher than conventional SCR. The application indicates that the annualized cost for hot SCR would be 50 percent more than conventional SCR. Please provide the vendor quotes for both conventional SCR and hot SCR. Also, please provide the parameters submitted to the vendor for preparation of the bid."

Response: These are submitted as Attachment E. For combined-cycle operation, several vendor quotes were analyzed to determine the costs for SCR systems yielding NO_x control of 2.5 ppmvd at 15-percent O_2, see Appendix E. Based on these vendor data, the following methods were utilized to estimate SCR catalyst cost, and SCR system cost for a control system yielding 2.5 ppmvd at 15-percent O_2:

- The SCR catalyst cost for a 2.5 ppmvd at 15-percent O_2 system equals the cost of a 3.5 ppmvd at 15-percent O_2 system plus the difference in catalyst costs from systems of 4.5- and 3.5 ppmvd at 15-percent O_2.
- The SCR system cost for a 2.5 ppmvd at 15-percent O_2 system equals the system cost of a 3.5 ppmvd at 15-percent O_2 system plus the difference in catalyst cost of 3.5- and 2.5 ppmvd at 15-percent O_2 systems.

Comment 8c: "The Department disputes that hot SCR is "technically infeasible" as described in the application. Recent discussions with regulatory agencies in California indicate that such systems have been designed, installed, and are functioning properly. Please comment."

Response: In California, the majority of simple cycle projects with "hot" SCR are smaller gas turbines exclusively fired with natural gas. The proposed Project will utilize the GE Frame 7FA turbine with higher exhaust temperatures and will use light distillate oil as an alternate fuel. Based on the lack of demonstration of hot SCR on dual fuel gas turbines and anticipated technical difficulties associated with oil firing, hot SCR is not considered technically feasible for GE Frame 7FA turbines. Moreover, FDEP has concluded on many simple cycle projects that "hot" SCR is not appropriate as BACT. This includes Martin Units 8A and 8B (simple cycle). The Martin Unit 8 Project is a combined cycle project and FPL is seeking simple cycle operation only for a limited number of hours. This includes the first year of operation and limited operation when combined cycle operation has commenced. For combined cycle, SCR systems operating at 650 to 750°F are technically feasible, available and demonstrated for the Martin Unit 8 Project.

Comment 8d: "Page 4-12 lists four facilities with hot SCR installed on simple cycle units in the early 1990s, which had problems with catalyst deactivation. Did these facilities utilize the same high-temperature zeolite catalyst that is currently being offered by the Engelhard Corporation? Have improvements in high-temperature catalysts been made since these projects were installed? Does the exhaust gas of the GE Frame 7FA approach 1200°F frequently? Under what conditions? What is the maximum operating temperature for Engelhard's new zeolite catalyst?"

Response: Engelhard has installed the zeolite catalyst on GE 7EA units and has no experience with installation on GE 7 FA CTs. Currently the maximum temperature range for hot SCR is 650°F - 1050°F with the zeolite catalyst applied to a ceramic substrate. The exhaust temperature of the GE 7FA CT in simple cycle mode is frequently at or above the maximum zeolite catalyst temperature of 1100°F, see application Appendix 10.1, Tables 2-3 and 2-4. Engelhard is also the only supplier of "hot" SCR limiting the alternative.

Comment 8e: "For the purchased equipment costs identified in the Table B-3, was the catalyst included in this cost? The annualized cost table includes an 'annualized catalyst cost'. What methods were used to ensure that the catalyst component was not "double-counted?"

Response: The cost for the SCR catalyst is not "double-counted" in the economic analysis. The initial catalyst cost is included in the purchase equipment costs identified in Table B-3. This cost is then annualized. The replacement costs for the SCR catalyst are contained in the determination of annualized operating costs. The economic analysis employs the standard procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). This is a standard economic convention universally used in economic analyses.

Since the cost of the SCR catalyst is a large portion of the overall equipment cost, the annualized cost of equipment can also be estimated using an alternative approach to the economic analysis. In this approach the annualized capital cost of the catalyst and the annual replacement cost is omitted and replaced with a "recurring" capital cost. The recurring capital cost is based on the guaranteed life of the catalyst (3 years) and the 7 percent rate used in determining annualized cost. The capital recovery factor in this case is 0.3811. The following calculation using this method illustrated this alternative approach. The calculation is based on the costs presented in Table B-4 of the Air Permit/PSD Application for SCR at 3.5 ppmvd corrected to 15-percent O_2 (Appendix 10.1.5).

Annualized Cost in Table B-4	$1,136,656
Deletion of catalyst from annualized cost	-$68,625 ($625,000 x 0.1098)
Deletion of annual catalyst cost	-$214,583 ($625,000/3 x 1.03)
Annualized cost less catalyst	$853,448
Recurring Capital Cost	$238,187 ($625,000 x 0.3811)
Alternate Annualized Cost Calculation	$1,091,636 ($853,448 + 238,187)

Using this method the annualized cost is about 4 percent lower than the method used in the BACT analysis. This small difference does not substantially change the economic evaluation.

<u>Comment 8f</u>: "Please describe the calculation of the heat rate penalty in Table B-4. Does this cost include "lost revenue"? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment."

<u>Response</u>: Lost revenue is not included in determining the calculation of the heat rate penalty. The heat rate penalty in Table B-4 is based on 0.3 percent power output of the SCR and a 0.3 percent increase in the cost of producing that power. When there is a heat rate penalty, there is a concomitant loss of power produced as well as an increased cost to produce power. This increases the overall cost to produce power. The heat rate penalty is calculated as follows based on two components. The first accounts for cost associated with incremental cost of producing power (all incremental costs other than fuel) while the second accounts for increased fuel costs.

Heat Rate = (0.003)(172.3 MW Turbine Capacity)(8760 hr/year)(1000 kW/MW)($0.04/kWh)+
(0.003)(1,776 MMBtu)($3 MMBtu/scf)(8760 hr/year).

Comment 9a: "Catalytic Oxidation System Costs

Please provide the vendor quotes for the catalytic oxidation system, including the parameters submitted to the vendor for preparation of the bid."

Response: These are submitted as Attachment E.

Comment 9b: "For the purchased equipment costs identified in the Table B-8, was the catalyst included in this cost? The annualized cost table includes an 'annualized catalyst cost'. What methods were used to ensure that the catalyst component was not 'double-counted'?"

Response: The cost for the oxidation catalyst is not "double-counted" in the economic analysis. The initial catalyst cost is included in the purchase equipment costs identified in Table B-3. The replacement costs for the oxidation catalyst are contained in the determination of annualized operating costs. The economic analysis employs the standard procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). This is a standard economic convention universally used in economic analysis (See also Response to 6jj).

Comment 9c: "Please describe the calculation of the heat rate penalty in Table B-9. Does this cost include 'lost revenue'? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment."

Response: The heat rate penalty in Table B-9 is based on 0.2% power output of the CO Catalyst and a 0.2% increase in the cost of producing that power. When there is a heat rate penalty, there is a concomitant loss of power produced as well as an increased cost to produce power. This increases the cost to produce power. The heat rate penalty is calculated as follows (Refer to Comment 6kk):

Heat Rate = (0.002)(172.3 MW Turbine Capacity)(8760 hr/year)(1000 kW/MW)($0.04/kWh)+
(0.002)(1,776 MMBtu)($3/MMBtu gas cost)(8760 hr/year).

Comment 10: "Additional Air Quality Impacts Analysis: Please submit the following information as required by Rule 62-212.400(5)(h), F.A.C."

"Information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7,1977, in the area the facility or modification would affect."

Response: There has been minimal industrial, commercial, and residential growth within a 5-mile radius of the FPL Martin Plant site since 1977. The site itself consists of 11,300 acres that is wholly owned by FPL. The site is comprised of a 6,800-acre cooling pond and approximately 400 acres for the existing power facilities. The remaining area consists of undeveloped or agricultural land.

The plant is located in a rural area of Martin County that has a minimal number of air pollution industrial and commercial sources near the site. Since the baseline date of August 7, 1977, there has been one major facility (Indiantown Cogeneration) built and operating within a 10-mile radius. As presented in Section 6 of the Air Permit/PSD Application (Appendix 10.1.5), a cumulative impact analysis was conducted for SO_2 and included the Indiantown Cogeneration Facility.

There are also very few residences near the plant site. The site is almost completely surrounded by undeveloped or agricultural areas with no incorporated towns or cities within a 5-mile radius. A small, undeveloped portion of the community of Indiantown is located just within 5 miles of the site and a sparsely populated subdivision of Sunset Groves lies to the north of the site.

The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require. Construction of the Project will occur over a 24-month period requiring an average of approximately 250 workers during that time. It is anticipated that many of these construction personnel will commute to the Site. At project build-out the plant will employ a total of 12 operational workers. This workforce needed to operate the proposed Project represents a small fraction of the population present in the immediate area. Population and housing impacts from construction and operation will be minimal because little migration into the area is anticipated. Additionally, there are expected to be no air quality impacts due to associated industrial/commercial growth given the location at the existing Martin Plant.

Since 1977, Martin County has been classified as attainment for all criteria pollutants. Although air monitoring data are not collected in the county, PM_{10}, O_3, and NO_2 concentrations are measured in St. Lucie County, located to the north of Martin County. These data are considered to be representative of air quality in Martin County due to the types and levels of air pollutants emitted from similar sources. Air monitoring data are collected for PM_{10}, O_3, SO_2 and CO in Palm Beach County, but these data are representative of air quality for areas with more industrial development than that around the Martin Plant site. The SO_2 and CO from Palm Beach County can be used, however, as a conservative indication of the air quality in Martin County.

A summary of the maximum pollutant concentrations measured in St. Lucie and Palm Beach Counties from 1998 through 2001 is presented in Table 2.3-13 of the SCA application. These data indicate that the maximum air quality concentrations measured in the region comply with and are well below the applicable ambient air quality standards.

Additionally, results of air modeling analyses demonstrate that the Project by itself and with other emission sources will comply with all applicable AAQS and PSD increments.

Comment 11: "EPA/NPS Comments: When received, the Department will forward any review submitted by the EPA Region 4 office or the National Park Service for comment. "

Response: Comment acknowledged. No comments were received as of the date of submittal of responses.

Comment 12: "Questions Regarding the Air Quality Analysis: The Department will submit questions and comments regarding its review of the air quality analysis before March 20, 2002."

Response: The Department did not provide comments regarding the air quality analysis.

ATTACHMENT A

GE DATA SHEETS FOR

UNITS 8A AND 8B

FPL MARTIN PLANT Distillate fuel
BASELOAD FOGGED TO 95% RH FROM 60 DEG-F
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	50.	60.	70.	80.
Evap. Cooler Status		None	On	On	On
Evap. Cooler Effectiveness	%		95	95	95
Fuel Type		Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78	1.78
Output	kW	185,300.	184,000.	180,200.	175,800.
Heat Rate (LHV)	Btu/kWh	9,945.	9,940.	9,955.	9,985.
Heat Cons. (LHV) X 10^6	Btu/h	1,842.8	1,829.	1,793.9	1,755.4
Auxiliary Power	kW	1,390	1,390	1,390	1,390
Output Net	kW	183,910.	182,610.	178,810.	174,410.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,020.	10,030.	10,060.
Exhaust Flow X 10^3	lb/h	3750.	3719.	3649.	3573.
Exhaust Temp.	Deg F.	1089.	1093.	1102.	1111.
Exhaust Heat (LHV) X 10^6	Btu/h	1016.5	1012.5	996.4	980.4
Water Flow	lb/h	124,260.	119,340.	114,320.	107,900.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.
NOx AS NO2	lb/h	325.	322.	316.	309.
CO	ppmvd	20.	20.	20.	20.
CO	lb/h	66.	65.	64.	62.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	15.	14.	14.
VOC	ppmvw	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.5	7.	7.
SO2	ppmvw	11.0	11.0	11.0	11.0
SO2	lb/h	95.0	94.0	93.0	91.0
SO3	ppmvw	1.0	1.0	1.0	1.0
SO3	lb/h	7.0	7.0	6.0	6.0
Sulfur Mist	lb/h	10.0	10.0	10.0	10.0
Particulates	lb/h	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.85	0.86	0.85
Nitrogen	71.47	71.19	70.94	70.63
Oxygen	11.10	11.04	10.98	10.92
Carbon Dioxide	5.57	5.56	5.55	5.54
Water	11.01	11.37	11.68	12.07

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60

Application	7FH2 Hydrogen-Cooled Generator
Combustion System	9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

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FPL MARTIN PLANT DISTILLATE FUEL GUARANTEE POINT
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Output	kW	172,200.
Heat Rate (LHV)	Btu/kWh	10,090.
Heat Cons. (LHV) X 10^6	Btu/h	1,737.5
Auxiliary Power	kW	1,390
Output Net	kW	170,810.
Heat Rate (LHV) Net	Btu/kWh	10,170.
Exhaust Flow X 10^3	lb/h	3552.
Exhaust Temp.	Deg F.	1113.
Exhaust Heat (LHV) X 10^6	Btu/h	971.0
Water Flow	lb/h	111,950.

EMISSIONS		
NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	307.
CO	ppmvd	20.
CO	lb/h	62.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	3.5
VOC	lb/h	7.
SO2	ppmvw	11.0
SO2	lb/h	90.0
SO3	ppmvw	1.0
SO3	lb/h	6.0
Sulfur Mist	lb/h	9.0
Particulates	lb/h	17.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.85
Nitrogen		70.94
Oxygen		11.00
Carbon Dioxide		5.54
Water		11.68

SITE CONDITIONS		
Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Liquid Fuel, H/C Ratio Of 1.82
Fuel LHV	Btu/lb	18387 @ 60 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.
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FPL Martin Plant Distillate Fuel Base Load over ambient range
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	0.	35.	59.	75.	95.
Ambient Relative Humid.	%	2.0	20.0	60.0	60.0	50.0
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60	60
Liquid Fuel H/C Ratio		1.82	1.78	1.78	1.78	1.78
Output	kW	192,400.	190,500.	181,800.	173,900.	160,600.
Heat Rate (LHV)	Btu/kWh	10,110.	9,945.	9,960.	10,020.	10,190.
Heat Cons. (LHV) X 10^6	Btu/h	1,945.2	1,894.5	1,810.7	1,742.5	1,636.5
Auxiliary Power	kW	1,390	1,390	1,390	1,390	1,390
Output Net	kW	191,010.	189,110.	180,410.	172,510.	159,210.
Heat Rate (LHV) Net	Btu/kWh	10,180.	10,020.	10,040.	10,100.	10,280.
Exhaust Flow X 10^3	lb/h	3928.	3862.	3683.	3552.	3376.
Exhaust Temp.	Deg F.	1066.	1074.	1098.	1113.	1131.
Exhaust Heat (LHV) X 10^6	Btu/h	1082.9	1042.6	1000.7	970.1	926.3
Water Flow	lb/h	134,140.	130,930.	120,720.	111,950.	98,570.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	343.	334.	319.	307.	289.
CO	ppmvd	20.	20.	20.	20.	20.
CO	lb/h	69.	68.	65.	62.	59.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	15.	15.	15.	14.	13.
VOC	ppmvw	3.5	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.5	7.5	7.	6.5
SO2	ppmvw	12.0	11.0	11.0	11.0	11.0
SO2	lb/h	101.0	98.0	94.0	90.0	85.0
SO3	ppmvw	0.0	1.0	1.0	1.0	1.0
SO3	lb/h	6.0	6.0	6.0	6.0	5.0
Sulfur Mist	lb/h	11.0	10.0	10.0	9.0	9.0
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.86	0.86	0.85	0.85
Nitrogen	71.84	71.79	71.31	70.94	70.52
Oxygen	11.13	11.19	11.06	11.00	11.00
Carbon Dioxide	5.62	5.56	5.56	5.54	5.46
Water	10.56	10.60	11.21	11.68	12.18

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

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FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 0 DEGF AND NEGLEGIBLE REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	192,400.	144,300.	96,200.
Heat Rate (LHV)	Btu/kWh	10,110.	10,680.	12,630.
Heat Cons. (LHV) X 10^6	Btu/h	1,945.2	1,541.1	1,215.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	191,010.	142,910.	94,810.
Heat Rate (LHV) Net	Btu/kWh	10,180.	10,780.	12,820.
Exhaust Flow X 10^3	lb/h	3928.	3076.	2521.
Exhaust Temp.	Deg F.	1066.	1107.	1154.
Exhaust Heat (LHV) X 10^6	Btu/h	1082.9	895.2	772.8
Water Flow	lb/h	134,140.	96,540.	67,700.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	343.	269.	210.
CO	ppmvd	20.	25.	36.
CO	lb/h	69.	69.	81.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	12.0	12.0	11.0
SO2	lb/h	101.0	80.0	63.0
SO3	ppmvw	<1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	4.0
Sulfur Mist	lb/h	11.0	8.0	7.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	71.84	72.17	72.81
Oxygen	11.13	11.19	11.73
Carbon Dioxide	5.62	5.64	5.38
Water	10.56	10.15	9.21

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	2
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

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FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	190,500.	142,900.	95,200.
Heat Rate (LHV)	Btu/kWh	9,945.	10,550.	12,500.
Heat Cons. (LHV) X 10^6	Btu/h	1,894.5	1,507.6	1,190.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	189,110.	141,510.	93,810.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,650.	12,690.
Exhaust Flow X 10^3	lb/h	3862.	3024.	2487.
Exhaust Temp.	Deg F.	1074.	1121.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	1042.6	868.7	752.4
Water Flow	lb/h	130,930.	94,620.	66,770.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	334.	263.	206.
CO	ppmvd	20.	24.	35.
CO	lb/h	68.	65.	77.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	98.0	78.0	61.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	5.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.87
Nitrogen	71.79	72.10	72.73
Oxygen	11.19	11.22	11.76
Carbon Dioxide	5.56	5.60	5.35
Water	10.60	10.23	9.29

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:00 FPL Martin dis load rge 35

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	181,800.	136,400.	90,900.
Heat Rate (LHV)	Btu/kWh	9,960.	10,620.	12,670.
Heat Cons. (LHV) X 10^6	Btu/h	1,810.7	1,448.6	1,151.7
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	180,410.	135,010.	89,510.
Heat Rate (LHV) Net	Btu/kWh	10,040.	10,730.	12,870.
Exhaust Flow X 10^3	lb/h	3683.	2936.	2435.
Exhaust Temp.	Deg F.	1098.	1137.	1182.
Exhaust Heat (LHV) X 10^6	Btu/h	1000.7	841.4	734.9
Water Flow	lb/h	120,720.	86,500.	61,390.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	253.	199.
CO	ppmvd	20.	24.	34.
CO	lb/h	65.	61.	73.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	94.0	75.0	60.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	3.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.88
Nitrogen	71.31	71.72	72.33
Oxygen	11.06	11.21	11.76
Carbon Dioxide	5.56	5.54	5.27
Water	11.21	10.68	9.77

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:01 FPL Martin dis load rge 59

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	75.	75.	75.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	173,900.	130,500.	87,000.
Heat Rate (LHV)	Btu/kWh	10,020.	10,750.	12,860.
Heat Cons. (LHV) X 10^6	Btu/h	1,742.5	1,402.9	1,118.8
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	172,510.	129,110.	85,610.
Heat Rate (LHV) Net	Btu/kWh	10,100.	10,870.	13,070.
Exhaust Flow X 10^3	lb/h	3552.	2871.	2389.
Exhaust Temp.	Deg F.	1113.	1149.	1193.
Exhaust Heat (LHV) X 10^6	Btu/h	970.1	823.5	721.0
Water Flow	lb/h	111,950.	80,050.	56,630.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	307.	245.	193.
CO	ppmvd	20.	23.	34.
CO	lb/h	62.	59.	71.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	90.0	72.0	58.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	6.0	5.0	4.0
Sulfur Mist	lb/h	9.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.86
Nitrogen	70.94	71.40	72.00
Oxygen	11.00	11.22	11.77
Carbon Dioxide	5.54	5.47	5.21
Water	11.68	11.06	10.17

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:02 FPL Martin dis load rge 75

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	160,600.	120,500.	80,300.
Heat Rate (LHV)	Btu/kWh	10,190.	11,010.	13,220.
Heat Cons. (LHV) X 10^6	Btu/h	1,636.5	1,326.7	1,061.6
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	159,210.	119,110.	78,910.
Heat Rate (LHV) Net	Btu/kWh	10,280.	11,140.	13,450.
Exhaust Flow X 10^3	lb/h	3376.	2758.	2323.
Exhaust Temp.	Deg F.	1131.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	926.3	793.5	695.9
Water Flow	lb/h	98,570.	70,300.	49,100.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	289.	232.	183.
CO	ppmvd	20.	24.	36.
CO	lb/h	59.	57.	74.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	6.5	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	85.0	69.0	55.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	7.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	70.52	70.99	71.61
Oxygen	11.00	11.25	11.86
Carbon Dioxide	5.46	5.38	5.07
Water	12.18	11.54	10.60

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:03 FPL Martin dis load rge 95

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	50.	60.	70.	80.
Evap. Cooler Status		None	On	On	On
Evap. Cooler Effectiveness	%		95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290	290
Output	kW	177,200.	176,000.	171,700.	166,700.
Heat Rate (LHV)	Btu/kWh	9,215.	9,235.	9,280.	9,350.
Heat Cons. (LHV) X 10^6	Btu/h	1,632.9	1,625.4	1,593.4	1,558.6
Auxiliary Power	kW	560	560	560	560
Output Net	kW	176,640.	175,440.	171,140.	166,140.
Heat Rate (LHV) Net	Btu/kWh	9,240.	9,260.	9,310.	9,380.
Exhaust Flow X 10^3	lb/h	3602.	3577.	3512.	3444.
Exhaust Temp.	Deg F.	1110.	1113.	1119.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	969.0	965.8	949.6	933.2

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.
NOx AS NO2	lb/h	60.	60.	58.	57.
CO	ppmvd	9.	9.	9.	9.
CO	lb/h	29.	29.	28.	28.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	14.	14.	14.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.8	2.8
Particulates	lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.89	0.88	0.88
Nitrogen	74.62	74.19	73.84	73.38
Oxygen	12.47	12.35	12.28	12.19
Carbon Dioxide	3.89	3.89	3.87	3.86
Water	8.14	8.69	9.13	9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:39 FPL Martin gas BL fogg rge

FPL Martin Plant Gas Fuel Guarantee Point
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Output	kW	162,100.
Heat Rate (LHV)	Btu/kWh	9,440.
Heat Cons. (LHV) X 10^6	Btu/h	1,530.2
Auxiliary Power	kW	560
Output Net	kW	161,540.
Heat Rate (LHV) Net	Btu/kWh	9,470.
Exhaust Flow X 10^3	lb/h	3418.
Exhaust Temp.	Deg F.	1128.
Exhaust Heat (LHV) X 10^6	Btu/h	921.4
EMISSIONS		
NOx	ppmvd @ 15% O2	9.
NOx AS NO2	lb/h	56.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0
EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		73.88
Oxygen		12.36
Carbon Dioxide		3.84
Water		9.04
SITE CONDITIONS		
Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/28/2000 17:20 FPL Martin gas BL rge

Gas Fuel

LOAD RANGE AT 0 DEGF AND NEGLEGIBLE REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	189,100.	141,800.	94,600.
Heat Rate (LHV)	Btu/kWh	9,250.	9,860.	11,780.
Heat Cons. (LHV) X 10^6	Btu/h	1,749.2	1,398.1	1,114.4
Auxiliary Power	kW	560	560	560
Output Net	kW	188,540.	141,240.	94,040.
Heat Rate (LHV) Net	Btu/kWh	9,280.	9,900.	11,850.
Exhaust Flow X 10^3	lb/h	3885.	3070.	2514.
Exhaust Temp.	Deg F.	1068.	1101.	1149.
Exhaust Heat (LHV) X 10^6	Btu/h	1040.5	863.3	750.0
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	64.	51.	40.
CO	ppmvd	9.	9.	9.
CO	lb/h	32.	25.	21.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.89	0.89
Nitrogen		75.18	75.17	75.28
Oxygen		12.65	12.64	12.94
Carbon Dioxide		3.87	3.88	3.74
Water		7.41	7.42	7.15
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	3		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:34 gas BL LOAD rge 0

FPL Martin Plant Gas Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,200.	136,700.	91,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,855.	11,820.
Heat Cons. (LHV) X 10^6	Btu/h	1,673.5	1,347.2	1,076.8
Auxiliary Power	kW	560	560	560
Output Net	kW	181,640.	136,140.	90,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,900.	11,890.
Exhaust Flow X 10^3	lb/h	3706.	2979.	2456.
Exhaust Temp.	Deg F.	1095.	1122.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	991.1	831.5	725.6
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	61.	49.	39.
CO	ppmvd	9.	9.	9.
CO	lb/h	30.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.90	0.90	0.90
Nitrogen		75.07	75.10	75.21
Oxygen		12.60	12.67	12.99
Carbon Dioxide		3.88	3.85	3.70
Water		7.56	7.49	7.21
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	20		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:44 FPL Martin gas BL LOAD rge 35

FPL Martin Plant Gas Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	173,000.	129,800.	86,500.
Heat Rate (LHV)	Btu/kWh	9,250.	10,000.	12,050.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.3	1,298.	1,042.3
Auxiliary Power	kW	560	560	560
Output Net	kW	172,440.	129,240.	85,940.
Heat Rate (LHV) Net	Btu/kWh	9,280.	10,040.	12,130.
Exhaust Flow X 10^3	lb/h	3539.	2888.	2396.
Exhaust Temp.	Deg F.	1116.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	951.8	807.5	707.9
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.88	0.90	0.90
Nitrogen		74.42	74.46	74.58
Oxygen		12.44	12.57	12.90
Carbon Dioxide		3.87	3.81	3.66
Water		8.39	8.27	7.97

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:45 FPL Martin gas BL LOAD rge 59

FPL Martin Plant Gas Fuel

LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	75.	75.	75.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	163,700.	122,800.	81,900.
Heat Rate (LHV)	Btu/kWh	9,380.	10,190.	12,330.
Heat Cons. (LHV) X 10^6	Btu/h	1,535.5	1,251.3	1,009.8
Auxiliary Power	kW	560	560	560
Output Net	kW	163,140.	122,240.	81,340.
Heat Rate (LHV) Net	Btu/kWh	9,410.	10,240.	12,410.
Exhaust Flow X 10^3	lb/h	3418.	2803.	2336.
Exhaust Temp.	Deg F.	1128.	1153.	1195.
Exhaust Heat (LHV) X 10^6	Btu/h	921.1	786.3	692.2

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	56.	45.	36.
CO	ppmvd	9.	9.	9.
CO	lb/h	28.	23.	19.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.88	0.89
Nitrogen	73.88	73.93	74.04
Oxygen	12.36	12.49	12.83
Carbon Dioxide	3.84	3.78	3.62
Water	9.04	8.92	8.62

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:54 FPL Martin gas BL LOAD rge 75

FPL Martin Plant Gas Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	150,300.	112,800.	75,200.
Heat Rate (LHV)	Btu/kWh	9,630.	10,550.	12,770.
Heat Cons. (LHV) X 10^6	Btu/h	1,447.4	1,190.	960.3
Auxiliary Power	kW	560	560	560
Output Net	kW	149,740.	112,240.	74,640.
Heat Rate (LHV) Net	Btu/kWh	9,670.	10,600.	12,870.
Exhaust Flow X 10^3	lb/h	3257.	2694.	2267.
Exhaust Temp.	Deg F.	1143.	1170.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	881.8	761.2	667.1
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	53.	43.	35.
CO	ppmvd	9.	9.	9.
CO	lb/h	26.	22.	18.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.6	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.88	0.87	0.87
Nitrogen		73.16	73.20	73.34
Oxygen		12.27	12.41	12.80
Carbon Dioxide		3.78	3.72	3.54
Water		9.92	9.80	9.45

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:56 FPL Martin gas BL LOAD rge 95

FPL Martin Plant Gas fuel with Steam Power Augmentation
Augmentation only permitted above 59 degF

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE
Ambient Temp.	Deg F.	35.	95.
Ambient Relative Humid.	%	20.0	50.0
Fuel Type		Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835
Fuel Temperature	Deg F	290	290
Output	kW	180,400.	165,100.
Heat Rate (LHV)	Btu/kWh	9,245.	9,265.
Heat Cons. (LHV) X 10^6	Btu/h	1,667.8	1,529.7
Auxiliary Power	kW	560	560
Output Net	kW	179,840.	164,540.
Heat Rate (LHV) Net	Btu/kWh	9,270.	9,300.
Exhaust Flow X 10^3	lb/h	3706.	3372.
Exhaust Temp.	Deg F.	1095.	1130.
Exhaust Heat (LHV) X 10^6	Btu/h	991.6	927.1
Steam Flow	lb/h	0.	110,260.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	12
NOx AS NO2	lb/h	61.	82
CO	ppmvd	9.	15.
CO	lb/h	30.	44.
UHC	ppmvw	7.	7.
UHC	lb/h	15.	14.
VOC	ppmvw	1.4	1.4
VOC	lb/h	3.	2.8
Particulates	lb/h	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.83
Nitrogen	75.07	69.28
Oxygen	12.60	11.20
Carbon Dioxide	3.88	3.80
Water	7.56	14.89

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/24/2000 17:49FPL Martin gas BL stm aug 35_95.dat

FPL Martin Plant Gas fuel Steam Power Augmentation with Fogger at 80 degF

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	80.
Fogger Status		On
Fogger Effectiveness	%	95
Output	kW	165,000.
Heat Rate (LHV)	Btu/kWh	9,410.
Heat Cons. (LHV) X 10^6	Btu/h	1,552.7
Auxiliary Power	kW	560
Output Net	kW	164,440.
Heat Rate (LHV) Net	Btu/kWh	9,440.
Exhaust Flow X 10^3	lb/h	3444.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	933.1

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	76.
CO	ppmvd	15
CO	lb/h	47.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88
Nitrogen	73.38
Oxygen	12.19
Carbon Dioxide	3.86
Water	9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996

HENRYCO 01/24/2000 17:58FPL Martin gas BL stm aug 80 fogg.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	0.
Output	kW	196,900.
Heat Rate (LHV)	Btu/kWh	9,075.
Heat Cons. (LHV) X 10^6	Btu/h	1,786.9
Auxiliary Power	kW	560
Output Net	kW	196,340.
Heat Rate (LHV) Net	Btu/kWh	9,100.
Exhaust Flow X 10^3	lb/h	3927.
Exhaust Temp.	Deg F.	1073.
Exhaust Heat (LHV) X 10^6	Btu/h	1049.8

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	111.
CO	ppmvd	9.
CO	lb/h	32.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.90
Nitrogen		75.11
Oxygen		12.45
Carbon Dioxide		3.96
Water		7.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	1
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 11 72411298
HENRYCO 01/28/2000 19:41 FPL MARTIN PLANT Peak gas 0 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	35.
Output	kW	190,300.
Heat Rate (LHV)	Btu/kWh	9,080.
Heat Cons. (LHV) X 10^6	Btu/h	1,727.9
Auxiliary Power	kW	560
Output Net	kW	189,740.
Heat Rate (LHV) Net	Btu/kWh	9,110.
Exhaust Flow X 10^3	lb/h	3713.
Exhaust Temp.	Deg F.	1109.
Exhaust Heat (LHV) X 10^6	Btu/h	1015.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	105.
CO	ppmvd	9.
CO	lb/h	30.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		75.00
Oxygen		12.39
Carbon Dioxide		3.98
Water		7.74

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:49 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	59.
Output	kW	179,500.
Heat Rate (LHV)	Btu/kWh	9,225.
Heat Cons. (LHV) X 10^6	Btu/h	1,655.9
Auxiliary Power	kW	560
Output Net	kW	178,940.
Heat Rate (LHV) Net	Btu/kWh	9,250.
Exhaust Flow X 10^3	lb/h	3541.
Exhaust Temp.	Deg F.	1139.
Exhaust Heat (LHV) X 10^6	Btu/h	983.3

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	101.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	74.34
Oxygen	12.20
Carbon Dioxide	3.98
Water	8.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:46 FPL MARTIN PLANT Peak gas 59 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	75.
Output	kW	169,500.
Heat Rate (LHV)	Btu/kWh	9,370.
Heat Cons. (LHV) X 10^6	Btu/h	1,588.2
Auxiliary Power	kW	560
Output Net	kW	168,940.
Heat Rate (LHV) Net	Btu/kWh	9,400.
Exhaust Flow X 10^3	lb/h	3413.
Exhaust Temp.	Deg F.	1152.
Exhaust Heat (LHV) X 10^6	Btu/h	952.2

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	97.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		73.80
Oxygen		12.12
Carbon Dioxide		3.95
Water		9.25

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 75 dry.dat

FPL MARTIN PLANT Peak Firing
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	95.
Output	kW	156,100.
Heat Rate (LHV)	Btu/kWh	9,595.
Heat Cons. (LHV) X 10^6	Btu/h	1,497.8
Auxiliary Power	kW	560
Output Net	kW	155,540.
Heat Rate (LHV) Net	Btu/kWh	9,630.
Exhaust Flow X 10^3	lb/h	3238.
Exhaust Temp.	Deg F.	1172.
Exhaust Heat (LHV) X 10^6	Btu/h	910.7

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	91.
CO	ppmvd	9.
CO	lb/h	26.
UHC	ppmvw	7.
UHC	lb/h	13.
VOC	ppmvw	1.4
VOC	lb/h	2.6
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.88
Nitrogen		73.06
Oxygen		11.99
Carbon Dioxide		3.91
Water		10.16

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK	PEAK	PEAK
Ambient Temp.	Deg F.	60.	70.	80.
Evap. Cooler Status		On	On	On
Evap. Cooler Effectiveness	%	95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,600.	177,900.	172,500.
Heat Rate (LHV)	Btu/kWh	9,190.	9,260.	9,345.
Heat Cons. (LHV) X 10^6	Btu/h	1,678.1	1,647.4	1,612.
Auxiliary Power	kW	560	560	560
Output Net	kW	182,040.	177,340.	171,940.
Heat Rate (LHV) Net	Btu/kWh	9,220.	9,290.	9,380.
Exhaust Flow X 10^3	lb/h	3581.	3513.	3441.
Exhaust Temp.	Deg F.	1131.	1141.	1149.
Exhaust Heat (LHV) X 10^6	Btu/h	994.1	980.5	964.9
EMISSIONS				
NOx	ppmvd @ 15% O2	15.	15.	15.
NOx AS NO2	lb/h	103.	100.	99.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	28.	28.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	14.	14.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.87	0.88
Nitrogen		74.11	73.76	73.29
Oxygen		12.14	12.05	11.95
Carbon Dioxide		3.98	3.98	3.97
Water		8.88	9.34	9.91
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	60		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:57FPL MARTIN PLANT Peak gas fogg 607080.dat

FPL MARTIN PLANT Peak Firing with FPLE Fogger on

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK	PEAK	PEAK
Ambient Temp.	Deg F.	59.	75.	95.
Ambient Relative Humid.	%	60.	60.	50.
Fogger Status		On	On	On
Fogger Effectiveness	%	95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	183,000.	175,200.	166,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,300.	9,450.
Heat Cons. (LHV) X 10^6	Btu/h	1,680.9	1,629.4	1,569.6
Auxiliary Power	kW	560	560	560
Output Net	kW	182,440.	174,640.	165,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,330.	9,480.
Exhaust Flow X 10^3	lb/h	3588.	3478.	3356.
Exhaust Temp.	Deg F.	1130.	1145.	1158.
Exhaust Heat (LHV) X 10^6	Btu/h	995.4	972.4	945.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.	15.	15.
NOx AS NO2	lb/h	103.	99.	96.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	28.	27.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	14.	13.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.6
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.87	0.87
Nitrogen	74.14	73.54	72.64
Oxygen	12.15	12.01	11.81
Carbon Dioxide	3.98	3.97	3.95
Water	8.84	9.61	10.73

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

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

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:30 FPL MARTIN PLANT Peak gas fogg.dat

ATTACHMENT B

(NOTE: The vendor for the duct burner systems have not yet been selected. Table A-2A presents the natural gas duct burner emissions used in the PSD/Air Permit application. These duct burner emissions rates are representative of typical guarantees from various vendors. Following Table A-2A is information from vendors that can meet these requirements.)

Table A-2A Natural Gas Duct Burner Emissions: Full Duct Firing

Pollutant	Emission Rate (lb/MMBtu)	Heat Input (lb/MMBtu)	Emission Rate (lb/hr)
PM-10	0.01	550	5.5
NO_x	0.1	550	55.0
CO	0.08	550	44.0
VOC	0.016	550	8.8

< Back

Custom Designed Duct Burner

PowerPlus Duct Burner

Standard Gas Fired Duct Burner

Standard Oil Fired Duct Burner

Duct Burner General Information

Aftermarket

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PowerPlus Duct Burner

- **Engineered for the lowest emissions with "F" & "G" class turbines**
- **Optimum performance during turbine power augmentation modes.**
- **Proven field performance**

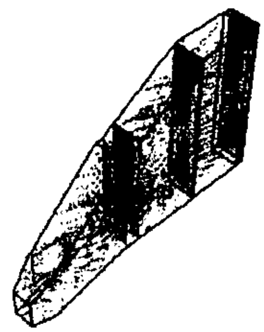
The Coen ***PowerPlus*** , built on three years of R&D and extensive field experience, introduces a new generation of duct burners to the power industry. Designed to handle the most challenging "Advanced Technology Turbines", ***PowerPlus*** provides unparalleled performance, quality, and reliability. The ***PowerPlus*** is the most reliable duct burner system in the world.

Duct Burner Design Fundamentals

Today's "Advanced Technology Turbine" has a lower O_2, and higher H_2O exhaust composition than previous gas turbine designs. This shift in exhaust temperature and composition reduces local flame temperatures and as a result has a significant impact on the duct burner stability range and CO contribution. Further, CO emission limits have been decreasing in recent years. As a result, Coen initiated a duct burner improvement program in R&D. The objectives were to identify CO formation pathways and develop reduction methods, while maintaining low NOx levels.

Through Computational Fluid Dynamics (CFD) modeling, coupled with Coen test facility experiments and field data, the following were established:

- Mixing rates and chemical kinetics were identified as the controlling factors in the modeling effort
- CO formation was identified as cooling of flame partial products with upstream turbine exhaust gas (TEG) prior to complete oxidation
- Reduction of CO, UBHC's (Unburned HydrocCarbons) and



Volatile Organic Compounds (VOC's) was proven to be directly related to increasing residence time in the flame stabilizer recirculation zone and decreased mixing rates in the near field zone

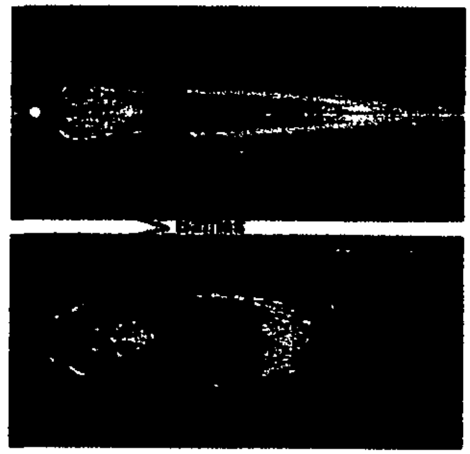
- Residence time can be increased with controlled flow baffle/flame stabilizer geometry, increased with reduced TEG velocity (until buoyancy limited) and increased with reduced turbulence

Tradeoffs of the above became obvious. Simple increases in flame stabilizer size and associated recirculation size resulted in the beneficial increased residence time, but was also offset by increased TEG velocity and turbulence.& Simple bluff bodies provided excessive turbulence and mixing rates in the near field, so streamlined flame stabilizers were desired for reduced pressure drop. How to increase residence time without increases in turbulence, pressure drop or TEG velocity? Reacting CFD models indicated that it was desired to obtain a long narrow recirculation zone that minimized mixing of TEG until complete oxidation. Hundreds of configurations were modeled and analyzed.

The answer was our ***PowerPlus*** flame stabilizer arrangement. It resulted in twin recirculation zones or as we have labeled "**Dual Recirculation Technology**". This dual recirculation pattern provides for increased residence time in a narrow "corridor" without excessive blockage or undesirable flame patterns. Typical residence times with ordinary stabilizers of ***any*** shape were approximately 50 milliseconds in the recirculation zone. The ***PowerPlus*** design increases this residence time by 3 times compared to current duct burner designs. Further TEG flow is diverted to the flame ends where oxidation is nearly complete. This concept has been modeled extensively, lab tested and field confirmed. Reduction in CO emissions of approximately 50% over previous flame stabilizer designs was achieved.

Case History CO and VOC Emissions

Current Design



The NOx emissions in duct burner systems are relatively low in comparison to ambient air fired burners. This is partially due to lower thermal NOx generation as a result of lower flame temperatures when firing with TEG as an oxidizer. Computational using only the extended Zeldovich mechanism, suggest that NOx emissions from duct burner systems should be lower than experimental data indicates. These computational results indicate that the ratio of prompt NOx to thermal NOx is higher in duct burner systems. A common passive method of total NOx reduction in duct burner systems is the utilization of re-burn. Re-burn is the concept of reducing incoming NOx (from the TEG) by reverse reactions from NOx to N2 in UHC rich flames. These reverse reaction rates are kinetically slow, therefore the limitation of re-burn NOx reduction is the amount of residence time in the re-burn zone. For duct burners the re-burn zone is the flame zone. Coen's ***PowerPlus*** duct burner has significant increases in residence time in the flame zone and as a consequence NOx reduction via re-burn.

The end result is our new ***PowerPlus*** duct burner. It produces the lowest NOx, CO, UBHC's and VOC emissions possible under any turbine exhaust condition!

For more information about this product, talk to your nearest Coen Sales Representative.

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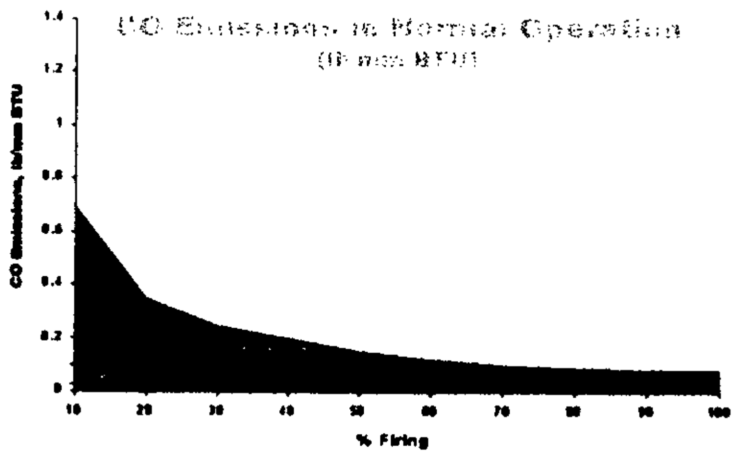
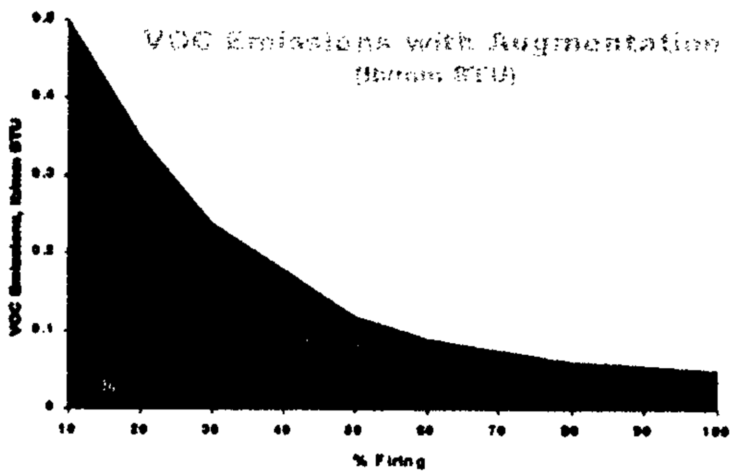
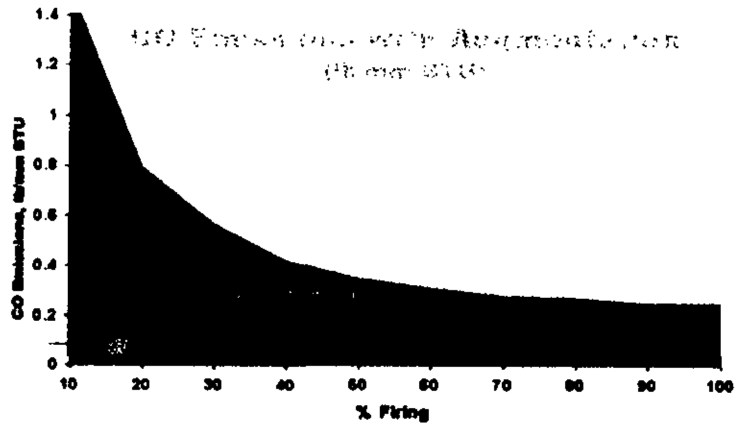
CO & VOC Emissions



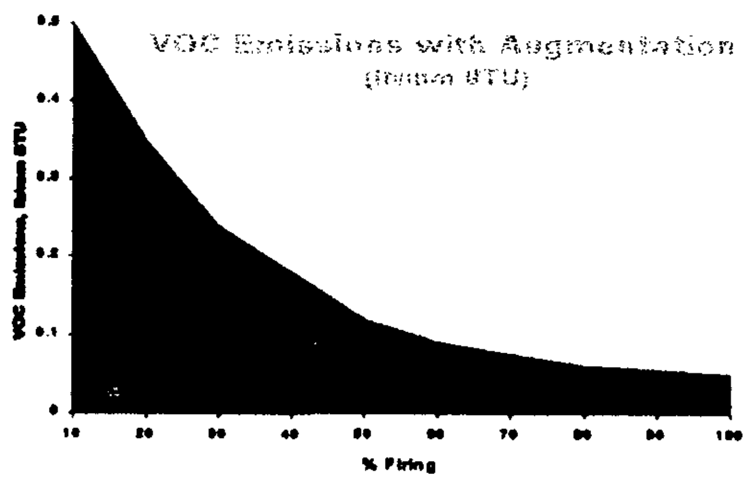
*Guaranteed Lowest Emissions ...**Under Any Condition!***



*Minimum 50% Reduction in CO and VOCs...**in any Mode!***



***No Augmenting Air!** No Increase in NOx! No Increase in Burner Pressure Drop!*



*Low Emissions in GT Power Augmentation Mode...**with No Supplemental Air!***

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DUCT BURNERS

ADVANTAGE DUCT BURNER

SCOPE OF SUPPLY

Horizontal (or vertical) Burner Elements (runners)
Integral Flow Baffles
ANSI B31.1 Fuel Skid with Integral PLC-based Burner Management System
Redundant Scanner Cooling Air Blowers (Skid Mounted)
Optional:

- Distribution Grids
- Pressure Reducing Stations
- Fuel Flow Measurement
- CFD and Physical Flow Modeling

APPLICATIONS

HRSG & Waste Heat Boilers
Industrial Cogeneration
Outstanding for Power Augmented GTs - can offset CO catalyst cost directly and SCR cost indirectly through GT water/steam injection
Low CO retrofits

APPLICATION SPECIFICATIONS

Duct cross sections of 3 to 50 feet
Heat inputs from 3 to 1200 MMBTU/HR
Inlet oxygen levels as low as 10.5% wet without augmenting air
Inlet H_2O as high as 20% without augmenting air
Typical TEG distribution to the burner ±25% of the avg. velocity over 90% of the cross section.

TYPICAL EMISSIONS

For most advanced gas turbine applications firing natural gas, we offer the following emission guarantees over turndown - without augmenting air:

Typical Guarantees (LB/MMBTU, HHV)

Non-Power Augmentation:

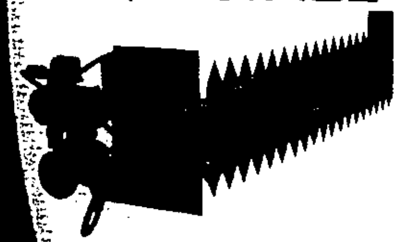
O2:	> 11.5% wet	NOx:	0.08
H2O:	< 12% wet	CO:	0.04
Burner Inlet TEG Temperature:	> 850°F	VOC:	0.004
Firing Temperatures:	> 1200°F		

Power Augmentation:

O2:	≥ 10.5% wet	NOx:	0.08
H2O:	> 12% wet	CO:	0.06
Burner Inlet TEG Temperature:	> 750°F	VOC:	0.006
Firing Temperatures:	> 1200°F		

DUCT BURNERS

ADVANTAGE



- **LOW CO AND VOC EMISSIONS** - up to 80% lower than recirculation-type burners - including over turn-down

- **LOW PRESSURE DROP & LOW NOx PERFORMANCE**- low emissions without efficiency loss

- **RELIABLE LIGHT-OFF** - High Energy Spark Ignition (HESI) for consistant performance in low oxygen and high water vapor environments

- **PATENT PENDING** design on mixing technology

- **NO AUGMENTING AIR REQUIRED** with TEG oxygen greater than 10.5% and water vapor as high as 20%

- **INVESTMENT CAST STABILIZERS** - Stainless steel stabilizers allow for long life and consistent performance

- **VORTEX SHEDDING ANALYSIS** - performed on each burner to ensure long life and trouble free operation

- **SHORT FLAME LENGTHS** - allows more mixing time to improve downstream temperature distribution

FORNEY

ATTACHMENT C

DUCT FIRING

Table A-1C Flue Gas Composition with CT and Duct Firing

lb/hr fuel (mmBtu/hr) -HHV	550	Air (lb/cf) Oxygen	(1)	0.167396	88861.4
Heating value (btu/cf)	1036	Air (lb/cf) Nitrogen	(1)	0.550712	
Fuel Flow (cf/hr)	530845.6	Prod (lb/cf) CO2	(1)	0.115072	61085.5
Fuel Flow (lb/hr)	22720.19	Prod (lb/cf) Water	(1)	0.093955	49875.6

Molecular Weight Calculation at 80 °F

Compound	Molecular Weight	Volume (Fraction)	Molecular Weight (Percent)
Argon	39.95	0.009	0.35
Nitrogen	28.01	0.734	20.56
Oxygen	32.00	0.122	3.90
Carbon Dioxide	44.01	0.039	1.70
Water	18.02	0.097	1.75
Carbon Monoxide	28.01	0	0.00
Nitrogen Dioxide	30.00	0	0.00
TOTAL		1.0001	28.25

Power Augmentation

	mass flow CT (lb/hr)	mass flow DB (lb/hr)	mass flow CT + DB (lb/hr)	volume flow (cf/hr)	(% flow)	Molecular Weight
Argon	42,849.8	0.0	42,849.8	1,254,979	0.009	0.37
Nitrogen	2,505,619.2	0.0	2,505,619.2	104,648,117	0.766	21.45
Oxygen	475,454.5	-88,861.4	386,593.0	14,135,218	0.103	3.31
Carbon Dioxide	207,066.4	61,085.5	268,151.9	7,128,730	0.052	2.30
Water	213,010.1	49,875.6	262,885.7	17,072,307	0.125	2.25
Total	3,444,000.0	22,099.6	3,466,099.6	144,239,351 acf/hr 2,403,989 acfm		29.68 MW

DUCT FIRING

Table A-1C Flue Gas Composition with CT and Duct Firing

lb/hr fuel (mmBtu/hr) -HHV	550	Air (lb/cf) Oxygen	(1)	0.167396	88861.4
Heating value (btu/cf)	1036	Air (lb/cf) Nitrogen	(1)	0.550712	
Fuel Flow (cf/hr)	530845.6	Prod (lb/cf) CO2	(1)	0.115072	61085.5
Fuel Flow (lb/hr)	22720.2	Prod (lb/cf) Water	(1)	0.093955	49875.6

Molecular Weight Calculation at 95 °F

Compound	Molecular Weight	Volume (Fraction)	Molecular Weight (Percent)
Argon	39.95	0.0088	0.35
Nitrogen	28.01	0.7316	20.49
Oxygen	32.00	0.1227	3.93
Carbon Dioxide	44.01	0.0378	1.66
Water	18.02	0.0992	1.79
Carbon Monoxide	28.01	0	0.00
Nitrogen Dioxide	30.00	0	0.00
TOTAL		1.0001	28.22

Case 1
based on Case 2 95 °F

	mass flow CT (lb/hr)	mass flow DB (lb/hr)	mass flow CT + DB (lb/hr)	volume flow (cf/hr)	(% flow)	Molecular Weight
Argon	40,568.6	0.0	40,568.6	1,188,166	0.009	0.35
Nitrogen	2,365,111.9	0.0	2,365,111.9	98,779,781	0.723	20.25
Oxygen	453,096.2	-88,861.4	364,234.8	13,317,721	0.097	3.12
Carbon Dioxide	191,979.5	61,085.5	253,065.0	6,727,649	0.049	2.17
Water	206,243.7	49,875.6	256,119.3	16,632,886	0.122	2.19
Total	3,257,000.0	22,099.6	3,279,099.6	136,646,203 acf/hr 2,277,437 acfm		28.08 MW

ATTACHMENT D

TABLES B-3A AND B-4A

Table B-3A. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$2,835,000	Vendor Estimate
Ammonia Storage Tank	$136,500	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$50,000	Additional NOx Monitor and System
Taxes	$170,100	6% of SCR Associated Equipment and Catalyst
Freight	$141,750	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,400,108	
Direct Installation Costs		
Foundation and supports	$272,009	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$476,015	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$136,004	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$68,002	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$34,001	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$34,001	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,040,032	
Total Capital Costs (TCC)	$4,440,140	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$444,014	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$222,007	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$444,014	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$88,803	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$44,401	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$133,204	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,426,444	
Total Direct, Indirect and Capital Costs (TDICC)	$5,866,584	Sum of TCC and TInCC

Table B-4A. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$55,220	$300 per ton for Aqueous NH3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$19,690	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$676,028	
Energy Costs		
Electrical	$37,968	80kW/h for SCR & 200kW/h for cooling @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$207,224	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$245,192	
Indirect Annual Costs		
Overhead	$46,049	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$58,666	1% of Total Capital Costs
Insurance	$58,666	1% of Total Capital Costs
Annualized Total Direct Capital	$644,151	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$807,531	
Total Annualized Costs	$1,728,751	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$13,636	NOx Reduction Only
	$25,214	Net Emission Reduction

ATTACHMENT E

(NOTE: The SCR vendor has not yet been selected. Typically the vendor is a subcontractor to the HRSG vendor since this control system is integrated into the design of the HRSG. The attached provides information on SCR and oxidation catalysts for a generic GE frame 7FA turbine in combined cycle and simple cycle. While this information is representative of system costs for comparisons with alternatives, actual system costs may be slightly higher or lower depending upon final design requirements.)

TABLE B-13. SCR, Oxidation Catalyst and $SCONO_x$ Control Equipment Costs for FPL Martin Unit 8

Operational and Cost Parameters	Value	Basis
NOx		
MW Capacity Net Gas @ 59 °F	172.44	Vendor Data
Heat Input CT Gas @ 59 °F	1,776.30	Vendor Data
Heat Rate (Btu/kW-hr)	10,301	Heat Input *10^6/MW Capacity/1000
Mass Flow CT Gas @ 59 °F	3,556,680	Vendor Data
Oxygen	12.44%	Vendor Data
Moisture	8.39%	Vendor Data
DB Heat Input	550	Vendor Data
Uncontrolled Emissions:		
NOx-Gas (lb/hr)	58.70	Vendor Data
NOx-Gas & DB (lb/hr)	113.70	Vendor Data
NOx-PA/DB or Oil (lb/hr)	319.2	Vendor Data
Controlled Emissions:		
NOx-Gas (lb/hr; 3.5 ppm)	22.83	NOx(lb/hr)*(3.5/9)
NOx-Gas & DB (lb/hr; 3.5 ppm)	33.08	NOx&DB(lb/hr)*(3.5/9)
NOx-PA/DB or Oil (lb/hr)	91.2	NOx-PA/DB(lb/hr)*(3.5/9)
NOx-Gas (lb/hr; 2.5 ppm)	16.31	NOx(lb/hr)*(2.5/9)
NOx-Gas & DB (lb/hr; 2.5 ppm)	23.63	NOx&DB(lb/hr)*(2.5/9)
NOx-PA/DB or Oil (lb/hr)	91.2	NOx-PA/DB(lb/hr)*(2.5/9)
Gas CT Only Hours	5380	Vendor Data
Gas & DB Hours	2880	Vendor Data
PA/DB or Oil Hours	500	Vendor Data
SO_2 (TPY)	68.6	Vendor Data
SCR System Cost (3.5 ppm)	$1,088,000	Engelhard Vendor Data
SCR Catalyst	$625,000	Engelhard Vendor Data
NH_3 Slip	9	Vendor Data
SCR System Cost (2.5 ppm)	$1,244,000	Estimated*
SCR Catalyst	$781,000	Estimated**
$SCONO_x$ System		
System Cost	$14,750,000	Vendor Data
Steam (lbs/hr)	17,795	Vendor Data
Gas (lb/hr)	80	Vendor Data
CO		
Uncontrolled Emissions:		
CO-Gas (lb/hr)	27.5	Vendor Data
CO-Gas & DB (lb/hr)	71.5	Vendor Data
CO-PA/DB or Oil (lb/hr)	64.7	Vendor Data
CO-Gas (ppmvd)	9	Vendor Data
CO-Gas & DB (ppmvd)	22.9	Vendor Data
CO-PA/DB or Oil (ppmvd)	20	Vendor Data
OC System Cost	$758,000	Engelhard Vendor Data
OC Catalyst	$659,000	Engelhard Vendor Data
VOC		
VOC-Gas (lb/hr)	2.74	Vendor Data
VOC-Gas & DB (lb/hr)	11.54	Vendor Data
VOC-PA/DB or Oil (lb/hr)	7.28	Vendor Data

*SCR System Cost @ 2.5 ppm = {(System Cost @ 3.5 ppm) - (Cat. Cost @ 3.5 ppm) + (Cat. Cost @ 2.5 ppm)}
** Catalyst Cost @ 2.5 ppm = {(Cat. Cost @ 3.5 ppm) - (Cat. Cost @ 4.5 ppm) + (Cat. Cost @ 3.5 ppm)}

Note: NO_x and NH_3 ppm concentrations given in ppmvd @ 15% O2, CO concentrations given in ppmvd.

TABLE B-12. Vendor Cost Data for SCR, Oxidation Catalyst and $SCONO_x$ Systems

Control Option	System Cost ($)	SCR Catalyst ($)	Turbine	Controlled Pollutant	Concentration Gas-In (ppm)	Concentration Gas-Out (ppm)	NOx Rate Oil (lb/hr)	Exhaust Mass Flow (lb/hr)	NH_3 Slip (ppm)	Pressure Drop (in H_2O)	Source	Date	$/lb/hr	$/lb/hr/%red
SCR System Cost	1,088,000.0 463,000.0	625,000.0	GE 7FA	NO_x	9	3.5	18.4	3,900,000	9	2.1	Engelhard	12/13/99	0.279 0.160	0.457 0.262
SCR System Cost	1,249,000.0 466,000.0	783,000.0	GE 7FA	NO_x	9	3.5	18.4	3,900,000	5	2.4	Engelhard	12/13/99	0.320 0.201	0.524 0.329
SCR System Cost	928,000.0 459,000.0	469,000.0	GE 7FA	NO_x	9	4.5	23.7	3,900,000	9	1.8	Engelhard	12/13/99	0.238 0.120	0.476 0.197
SCR System Cost	1,088,000.0 463,000.0	625,000.0	GE 7FA	NO_x	9	4.5	23.7	3,900,000	5	2.1	Engelhard	12/13/99	0.279 0.160	0.558 0.262
OC System Cost	758,000.0	659,000.0	GE 7FA	CO	9	0.9		3,900,000	9	2.1	Engelhard	12/13/99	0.194	0.216

	System Cost ($)	Turbine	Controlled Pollutant	Concentration Gas-In (ppm)	Concentration Gas-Out (ppm)	Natural Gas Cons. (lb/hr)	Exhaust Mass Flow (lb/hr)	Steam (lbs/hr)	Pressure Drop (in H_2O)	Source
$SCONO_x$ System	$14,750,000	GE 7FA	NO_x	9	3.5	80	3,900,000	17,795	3.4	Alstom

Note: NO_x and NH_3 ppm concentrations given in ppmvd @ 15% O2, CO concentrations given in ppmvd.

Calculations for 2.5 ppmvd				
17.24% Cost	16.67% Increased pressure drop	61.11% Removal for 9 to 3.5 ppm		
17.24%		72.22% Removal for 9 to 2.5 ppm		
		11.11%		
Calculations for Ammonia Slip				
14.80%				
			Ammonia 9 to 5 Impact	
	For 2.5 ppmvd:		SCR System	Catalyst
Catalyst Increase:	$156,000			
	$781,000			
System	$463,000		$161,000	$158,000
	$1,244,000			

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Simple Cycle

ASSUMED AMBIENT	59	59	59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F	1,100	1,100	1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000	3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63	75.23	71.63
O2	12.61	11.04	12.61	11.04
CO2	3.63	5.20	3.63	5.20
H2O	7.60	11.20	7.60	11.20
Ar	0.93	0.93	0.93	0.93
AMBIENT AIR FLOW, lb/hr	332,949	348,316	332,949	348,316
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	4,232,949	4,428,316	4,232,949	4,428,316
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.70	72.37	75.70	72.37
O2	13.09	11.64	13.09	11.64
CO2	3.35	4.80	3.35	4.80
H2O	7.01	10.33	7.01	10.33
Ar	0.86	0.86	0.86	0.86
CALCULATED AIR + GAS MOL. WT.	28.48	28.32	28.48	28.32
GIVEN: TURBINE CO, ppmvd	9.0	20.0	9.0	20.0
CALC.: TURBINE CO, lb/hr	31.9	71.7	31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	9.0	42.0	9.0	42.0
CALC.: TURBINE NOx, lb/hr	64.5	355.2	64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE	7.1	13.6	7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE	8.8	41.0	8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS				
CO CATALYST CO CONVERSION, %	90%	90%	90%	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12	5	12
SCR PRESSURE DROP, 4.0"WG – Nom.				
GUARANTEED PERFORMANCE DATA				
CO CONVERSION - % Min.	90.0%	90.0%	90.0%	90.0%
CO OUT, ppmvd @ 15% O2	0.7	1.4	0.7	1.4
CO OUT, lb/hr	3.2	7.2	3.2	7.2
CO PRESSURE DROP	2.2	2.4	2.2	2.4
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%	61.1%
NOx OUT, lb/hr – Max.	25.1	138.1	25.1	138.1
NOx OUT, ppmvd@15%O2 – Max.	3.4	16.0	3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	139	424	101	424
NH3 SLIP, ppmvd@15%O2 – Max.	9	12	5	12
SCR PRESSURE DROP, "WG - Max.	4.2	4.4	4.6	4.8
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft	1650.0		1650.0	
CO SYSTEM	$843,000		$843,000	
REPLACEMENT CO CATALYST MODULES	$643,000		$643,000	
SCR SYSTEM	$2,835,000		$3,046,000	
REPLACEMENT SCR CATALYST MODULES	$1,479,000		$1,690,000	

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Combined Cycle

GIVEN / CALCULATED DATA	GE 7F	GE 7F	GE 7F	GE 7F
FUEL	NG	OIL	NG	OIL
TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000	3,900,000	4,080,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63	75.23	71.63
O2	12.61	11.04	12.61	11.04
CO2	3.63	5.20	3.63	5.20
H2O	7.60	11.20	7.60	11.20
Ar	0.93	0.93	0.93	0.93
GIVEN: TURBINE CO, ppmvd	9	20	9	20
CALC.: TURBINE CO, lb/hr	31.9	71.7	31.9	71.7
CALC. TURBINE CO, ppmvd @ 15% O2	7.3	15.7	7.3	15.7
GIVEN: TURBINE NOx, ppmvd @ 15% O2	9	42	9	42
CALC.: TURBINE NOx, lb/hr	64.5	355.2	64.5	355.2
CALC. GAS MOL. WT.	28.45	28.45	28.45	28.45
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650	650
DESIGN REQUIREMENTS				
CO CATALYST CO OUT, ppmvd @ 15% O2	0.7	1.6	0.7	1.6
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12	5	12
GUARANTEED PERFORMANCE DATA				
CO CATALYST CO CONVERSION, % - Min.	90.0%	90.0%	90.0%	90.0%
CO OUT, lb/hr - Max.	3.2	7.2	3.2	7.2
CO OUT, ppmvd @ 15% O2 - Max.	0.7	1.6	0.7	1.6
CO PRESSURE DROP, "WG - Max.	1.2	1.3	1.2	1.3
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%	61.1%
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	18.4	3.5	18.4
NOx OUT, lb/hr - Max.	25.1	138.1	25.1	138.1
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	137.1	405.2	99.3	405.2
NH3 SLIP, ppmvd @ 15% O2 - Max.	9	12	5	12
SCR PRESSURE DROP, "WG - Max.	2.0	2.1	2.2	2.4
FIT HRSG INSIDE LINER - 67 ft H x 26 ft W				
CO SYSTEM	**$758,000**		**$758,000**	
REPLACEMENT CO CATALYST MODULES	**$659,000**		**$659,000**	
SCR SYSTEM	**$1,088,000**		**$1,249,000**	
REPLACEMENT SCR CATALYST MODULES	**$625,000**		**$783,000**	

FLORIDA

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

March 1, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John M. Lindsay, Plant General Manager
Florida Power and Light – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Re: **Request for Additional Information**
Project No. 0850001-010-AC (PSD-FL-327)
New Combined Cycle Unit No. 8

Dear Mr. Lindsay:

On February 1, 2002, the Department received your application and sufficient fee for an air construction permit to add new combined cycle Unit 8 to the existing Martin Plant. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Equipment Description: Please verify and comment on the information in the following description of equipment:

   Combined Cycle Unit No. 8 will be a "4 on 1" unit consisting of four 170 MW gas turbines, four gas-fired heat recovery steam generators (HRSGs), and one steam turbine-electrical generator.

   Gas Turbines: Each gas turbine (Unit Nos. 8A, 8B, 8C, and 8D) includes General Electric Model PG7241(FA) combustion turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a simple cycle exhaust stack that is 80 feet tall and 22.0 feet in diameter, fuel distribution systems, and ancillary support equipment. Exhaust gases will exit the simple cycle stack at approximately 1116° F with a volumetric flow rate of approximately 2,389,500 acfm.

   Heat Recovery Steam Generators (HRSGs): During combined cycle operation, the exhaust from each gas turbine will pass through a separate gas-fired heat recovery steam generator with an exhaust stack that is 120 feet tall and 19.0 feet in diameter. Exhaust gases will exit the HRSG stack at approximately 202° F with a volumetric flow rate of approximately 1,004,000 acfm.

   Fuels and Firing Rates: The primary fuel for each gas turbine is natural gas with very low sulfur distillate oil (≤ 0.05% sulfur by weight) serving as a backup fuel on a restricted basis. At a compressor inlet air temperature of 59° F, the maximum heat input rate of each gas turbine is 1600 MMBtu (LHV) per hour when firing natural gas and 1811 MMBtu (LHV) per hour when firing distillate oil. Each HRSG is designed with duct burners having a maximum heat input of 550 MMBtu (LHV) per hour when firing natural gas.

   Generating Capacity: At a compressor inlet air temperature of 59° F and the maximum heat input rate, each gas turbine generates a nominal 172 MW of shaft-driven electricity when firing natural gas and 180 MW of shaft-driven electricity when firing distillate oil. The single steam-turbine electrical generator is rated at a capacity of 470 MW. With all four gas turbines in operation and firing all HRSG duct burners, the combined cycle system generates a nominal 1150 MW of electricity.

   Controls: Each gas turbine incorporates General Electric's dry low-NOx combustion system (2.6) to minimize the formation of NOx emissions when firing natural gas. A water injection system will be installed to minimize NOx emissions when firing distillate oil. A conventional selective catalytic reduction (SCR) system will be installed in the HRSG to further reduce NOx emissions during combined cycle operation. The efficient combustion of very low sulfur fuels at high temperatures minimizes the emissions of CO, PM/PM10, SO2 and VOC.

Continuous Monitors: Each gas turbine will be equipped with continuous emissions monitoring systems (CEMS) to measure and record NOx emissions as well as flue gas carbon dioxide content.

2. Fuel Heaters: Please describe when fuel heating is necessary. Why will the gas-fired fuel heaters operate more during the first year of operation? Why aren't the fuel heaters necessary during combined cycle operation? Is there a separate heat transfer system used during combined cycle operation?

3. Cooling Tower: Please identify the determining factors in whether or not the proposed cooling tower will be installed.

4. Fuel Oil Tanks: The application indicates that the combined capacity of both fuel tanks will be approximately 2 million gallons. Based on the maximum firing rate of 14,000 gallons per hour per gas turbine, the tanks would only provide about 36 hours of simultaneous operation of all four units. Approximately how many truckloads of oil will it take to fill the two tanks? Approximately how long will it take to empty one truckload of oil? How long will it take to refill the tanks? Are there adequate roadways to provide access for this number of trucks? Describe how oil would be delivered and transferred to the tanks when the units were in operation and were expected to fire oil for an extended period of time, such as several days.

5. Operational Restrictions Requested: Please comment on the Department's interpretation of the following restrictions requested in the application.

   a. Each gas turbine shall fire no more than 500 hours of oil per consecutive 12 months (or equivalent oil consumption at full load).

      ➤ Because of higher emissions of nearly all pollutants when firing oil, the Department has restricted oil firing as part of its BACT determination for several recent projects. For similar projects, the Department has restricted oil firing to no more than 250 hours per year per gas turbine at full load. Please comment.

      ➤ The Department will consider this restricted operation in terms of hours of operation or fuel consumption (gallons). Please identify the preferred restriction in these terms.

   b. Duct firing shall not exceed an equivalent of 2880 hours per year per HRSG at full capacity.

      ➤ Please identify the requested restriction in terms of maximum hours of operation or gas consumption (million cubic feet of gas).

   c. Each gas turbine shall be limited to no more than 400 hours per consecutive 12 months of steam injection for power augmentation.

   d. Each gas turbine shall be limited to no more than 60 hours per consecutive 12 months of high temperature peaking operation.

   e. Excluding startup and shutdown, each gas turbine shall not operate below 50% of base load.

   f. Until capable of operating in combined cycle mode, each gas turbine shall operate no more than 3390 hours per consecutive 12 months.

   g. Once combined cycle operation is established, simple cycle operation of the four gas turbines shall not exceed an average of 1000 hours per consecutive 12 months. Operation of any individual gas turbine shall not exceed 3390 hours per consecutive 12 months.

   h. Please explain the requested "aggregate" limit for simple cycle operation and oil firing after the combined cycle unit begins operation.

   i. Note that all requested annual limits will be specified in terms of "consecutive 12 months".

6. Emissions

   a. Please provide General Electric's emissions data sheets for gas firing and oil firing including standard operation, power augmentation, and high temperature peaking at a compressor inlet air temperature of 59° F and 100% load.

b. Please provide the manufacturer's emissions data sheet for the duct burners. Provide supporting documents and/or calculations of the expected emission levels for the combined gas turbine exhaust and the duct burner emissions (CO, NOx, and VOC).

c. The proposed NOx BACT emission rate of 12.0 ppmvd @ 15% O_2 when firing oil in combined cycle mode is higher than recent Department permits, which have established a BACT limit of 10.0 ppmvd @ 15% O_2 for an identical gas turbine controlled by SCR. Please comment.

d. The proposed NOx BACT emission rate of 42.0 ppmvd @ 15% O_2 when firing oil in simple cycle mode is higher than recent Department permits, which have established BACT limits as low as 36.0 ppmvd @ 15% O_2 for an identical gas turbine controlled by wet injection. Please comment.

e. Please clarify the averaging period for the requested NOx limit (3-hour or 24-hour; see page 2-4 and Table 4-1).

f. General Electric has guaranteed CO emission rates of 7.4 and 14.4 ppmvd @ 15% O_2 for gas and oil firing for the Frame 7FA gas turbine. Please explain the proposed CO BACT emission rates of 9 and 20 ppmvd @ 15% O_2.

g. The requested CO BACT emission rates of 24.5 ppmvd @ 15% O_2 (gas firing with duct burning), 29.5 ppmvd @ 15% O_2 (gas firing with duct burning and power augmentation or peaking), and 20.0 ppmvd @ 15% O_2 (oil firing) do not represent current BACT levels of control for CO emissions. At these levels, the Department believes that an oxidation catalyst may be cost effective. Please comment.

h. Please provide supporting documentation that duct burning would increase CO emissions from 7.4 ppmvd @ 15% O_2 to 24.5 ppmvd @ 15% O_2 when firing natural gas. Verify that high temperature peaking would not increase CO emissions. Provide supporting documentation that duct burning with power augmentation would increase CO emissions from 24.5 ppmvd @ 15% O_2 to 29.5 ppmvd @ 15% O_2 when firing natural gas.

i. The application requests EPA Method 10 testing to demonstrate compliance with the CO standards. Based on recent PSD permits for identical units, the Department intends to require a CO CEMS. Please comment.

j. Please provide supporting documentation that duct burning would increase VOC emissions from 3.5 ppmvw to 7.0 ppmvw (when firing oil in the gas turbine).

k. The proposed visible emissions standard of 20% opacity when firing oil is inconsistent with recent Department permits for identical units, which limit opacity to 10% for all fuels. Please comment.

7. Excess Emissions: Please describe the "steam blow" process and explain why 90 days of steam blows are necessary at the beginning of operation for this project. Please describe the startup and shutdown procedures including the approximate lengths of time for each portion of the procedure (cold, warm, hot, simple cycle, and combined cycle). What are the critical parameters involved? What pollutants will be in "excess" of an emissions standard, what are the expected levels, and what will be the expected duration? Please provide supporting documentation.

8. SCR Costs

a. It appears that Tables B-3a and B-4a regarding hot SCR costs have been inadvertently omitted from the application. Please submit.

b. Based on a report prepared for the Department of Energy (Onsite Sycom, 11/99), the hot SCR costs appear to be much higher than expected. This report indicates that annualized costs for "hot SCR" for a large frame unit would be approximately 20% higher than conventional SCR. The application indicates that the annualized cost for hot SCR would be 50% more than conventional SCR. Please provide the vendor quotes for both conventional SCR and hot SCR. Also, please provide the parameters submitted to the vendor for preparation of the bid.

c. The Department disputes that hot SCR is "technically infeasible" as described in the application. Recent discussions with regulatory agencies in California indicate that such systems have been designed, installed, and are functioning properly. Please comment.

d. Page 4-12 lists four facilities with hot SCR installed on simple cycle units in the early 1990s, which had problems with catalyst deactivation. Did these facilities utilize the same high-temperature zeolite catalyst that is currently being offered by the Engelhard Corporation? Have improvements in high-temperature catalysts been made since these projects were installed? Does the exhaust gas of the GE Frame 7FA approach 1200° F frequently? Under what conditions? What is the maximum operating temperature for Engelhard's new zeolite catalyst?

e. For the purchased equipment costs identified in the Table B-3, was the catalyst included in this cost? The annualized cost table includes an "annualized catalyst cost". What methods were used to ensure that the catalyst component was not "double-counted"?

f. Please describe the calculation of the heat rate penalty in Table B-4. Does this cost include "lost revenue"? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment.

9. Catalytic Oxidation System Costs

a. Please provide the vendor quotes for the catalytic oxidation system, including the parameters submitted to the vendor for preparation of the bid.

b. For the purchased equipment costs identified in the Table B-8, was the catalyst included in this cost? The annualized cost table includes an "annualized catalyst cost". What methods were used to ensure that the catalyst component was not "double-counted"?

c. Please describe the calculation of the heat rate penalty in Table B-9. Does this cost include "lost revenue"? EPA guidance does not allow for the inclusion of "lost revenue" in determining control equipment costs for purposes of BACT. Please comment.

10. Additional Air Quality Impacts Analysis: Please submit the following information as required by Rule 62-212.400(5)(h), F.A.C.

"5. Information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7,1977, in the area the facility or modification would affect."

11. EPA/NPS Comments: When received, the Department will forward any review submitted by the EPA Region 4 office or the National Park Service for comment.

12. Questions Regarding the Air Quality Analysis: The Department will submit questions and comments regarding its review of the air quality analysis before March 20, 2002.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

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

AAL/jfk

cc: Mr. K. H. Simmons, FPL – Environmental Services
Mr. Willie Welch, FPL – Martin Plant
Mr. Ken Kosky, Golder Associates Inc.
Mr. Tom Tittle, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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1. Article Addressed to:

Mr. John M. Lindsay
Plant General Manager
Florida Power & Light - Martin Plant
P. O. Box 176
Indiantown, FL 34956

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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

February 6, 2002

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

RE: FPL Martin Plant
1150 MW Combined Cycle Unit
DEP File No. 0850001-010-AC, PSD-FL-327

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Florida Power and Light to expand the electrical generating capacity of their existing Martin Power Plant in Martin County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Jeff Koerner, review engineer, at 850/921-9536.

Sincerely,

Patty Adams

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

AAL/pa

Enclosure

Cc: J. Koerner

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 5, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, GA 30303

Re: FPL Martin Power Plant
Description: 1150 MW Combined Cycle Unit
Project No. 0850001-010-AC (PSD-FL-327)

Dear Mr. Worley:

Enclosed for your review and comment is an application to expand the electrical generating capacity of the existing FPL Martin Power Plant. The project will create a "4 on 1" combined cycle unit with a nominal capacity of 1150 MW. It will consist of two new Frame 7 FA gas turbines (≈ 170 MW each), two existing simple cycle Frame 7FA gas turbines (≈ 170 MW each), four new gas-fired HRSGs, and a single steam-electrical generator (≈ 470 MW). FPL proposes the following standards as BACT:

- NOx: 2.5 (gas)/12 ppmvd (oil) @ 15% O_2, 24-hour CEMS average; DLN combustion, water injection and SCR;
- CO: 9 (gas)/20 (oil) @ 15% O_2, combustion design;
- PM, SO_2, and VOC: efficient combustion of clean fuels.

FPL also requests some simple cycle operation, 500 hours per year of oil firing per unit, duct firing, and power augmentation. FPL proposes slightly higher emissions standards for these alternate methods of operation. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Jeffery F. Koerner

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

AAL/jfk

Enclosures

"More Protection, Less Process"

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 5, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, GA 30303

Re: FPL Martin Power Plant
Description: 1150 MW Combined Cycle Unit
Project No. 0850001-010-AC (PSD-FL-327)

Dear Mr. Worley:

Enclosed for your review and comment is an application to expand the electrical generating capacity of the existing FPL Martin Power Plant. The project will create a "4 on 1" combined cycle unit with a nominal capacity of 1150 MW. It will consist of two new Frame 7 FA gas turbines (≈ 170 MW each), two existing simple cycle Frame 7FA gas turbines (≈ 170 MW each), four new gas-fired HRSGs, and a single steam-electrical generator (≈ 470 MW). FPL proposes the following standards as BACT:

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- CO: 9 (gas)/20 (oil) @ 15% O_2, combustion design;
- PM, SO_2, and VOC: efficient combustion of clean fuels.

FPL also requests some simple cycle operation, 500 hours per year of oil firing per unit, duct firing, and power augmentation. FPL proposes slightly higher emissions standards for these alternate methods of operation. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Jeffery J. Koerner

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

AAL/jfk

Enclosures