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1. Article Addressed to:

The Honorable Joe McClash
Manatee County Board of
County Commissioners
P.O. Box 1000
Bradenton, FL 34205

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C. Signature
X Terry L. Farnham ☐ Agent ☐ Addressee

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1. Article Addressed to:

Mr. William Mack, St.
Manageing Director
El Paso Merchant Energy Co.
1001 Louisiana St.
Houston, TX 77002

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery JAN 28 2002

C. Signature
X 1/28 ☐ Agent ☐ Addressee

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2. Article Number (Copy from service label) 7001 0320 0001 3692 8604

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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. William Mack, Sr., Managing Director
El Paso Merchant Energy Company
1001 Louisiana Street
Houston, Texas 77002

DEP File No. 0810199-001-AC (PSD-318)
Manatee Energy Center
Manatee County

Enclosed is the Final Permit Number 0810199-001-AC (PSD-FL-318) to construct a 600 MW Power Plant called the Manatee Energy Center in Manatee County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/17/02 to the person(s) listed:

William Mack, El Paso*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Tom Davis, P.E., ECT
Chair, Manatee County BCC*
Karen Collins, PhD., Manatee County EMD
Jerry Campbell, Hillsborough County EPC
Peter Hessling, Pinellas County DEM

Clerk Stamp

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

Barbara J. Friday 1/17/02
(Clerk) (Date)

FINAL DETERMINATION
File No. 0810199-001-AC (PSD-FL-318)
MANATEE ENERGY CENTER
600 MW POWER PLANT FACILITY

The Department distributed a Public Notice package on September 11, 2001 for the project to construct a natural gas electrical power plant to be known as the Manatee Energy Center in Manatee County. The project consists of three (3) nominal 170 MW General Electric 7FA combustion turbine-electrical generators, an unfired heat recovery steam generator, a separate steam-electrical generator; three 135-foot stack; a mechanical draft cooling tower; one 2600-hp diesel generator, one 250-hp diesel fire pump, one gas heater, aqueous ammonia storage tank and small diesel storage tanks and other ancillary equipment. The Public Notice of Intent to Issue was published on September 20, 2001, in the Sarasota Herald-Tribune, Manatee County.

Written comments were received during the 30-day public comment period from EPA Region IV, the Manatee County Environmental Management Department (Manatee County), and from El Paso Merchant Energy Company (El Paso).

The comments from El Paso, Manatee County, and EPA along with the Department's responses are listed below.

El Paso Comments and Department Responses:

In reference to Permit Specific Conditions III.A.2 and 17, related to minimizing startup times and control of startup emissions, El Paso submitted a letter prepared by General Electric dated September 21, 2001. The Department had suggested that this could be done by installation of a separate bypass stack and damper to facilitate startup of the steam cycle while operating the combustion turbine in low emission modes 5, 5Q, and 6Q. GE commented as follows:

"Operating the damper door as a modulating valve is not recommended. We are aware of a similar application at a project at KEPCO (Hungary?). Because of the turbulent flows, damage to the damper door and its seals allowed leakage to the atmosphere after the damper was closed resulting in a significant loss in performance".

In reference to Condition III.A.8, El Paso submitted the following comment: "The 2000 hour per year limit on steam flow augmentation may be insufficient to meet plant operational objectives. The March 2001 Air Construction permit application submitted to the Department requested up to 8,760 hours per year of steam flow augmentation".

Following discussions with the Department, El Paso proposed to install "a HRSG stack damper (without a bypass stack) to reduce the frequency of cold and warm starts" and "an oxidation catalyst control system to minimize CO and VOC emissions occurring during startups and shutdowns ..... and power augmentation operating conditions".

Department Response:

The Department reviewed General Electric's letter and wrote an e-mail to their representative re-framing the issue and asking how startup emissions can be minimized for a combined cycle configuration and whether modulating valves (instead of dampers) can be designed for this purpose. General Electric's further input will be useful when reviewing future projects, but will not come in time to implement it into the present project.

The Department has determined that El Paso oxidation catalyst proposal is a proper solution for this project. It reflects the first installation of oxidation catalyst in a GE Frame 7FA combined cycle unit in the State of Florida. The oxidation catalyst certainly will reduce high emissions of CO that can occur during the prolonged cold startup of a combined cycle unit when the basic combustion turbine is operated outside of DLN modes.

The oxidation catalyst will further minimize emissions of CO and VOC under all other modes of operation, especially power augmentation. The CO emission limits will be reduced and the permit will be revised as follows:

<u>Section III.A. Emission Unit 001: Combined Cycle Turbine No. CC-1 (Controls)</u>: The efficient combustion of pipeline-quality natural gas at high temperature minimizes emissions of CO, PM/PM10, SAM, SO2, and VOC. A selective catalytic reduction (SCR) system combined with Dry Low NO_X combustion technology reduces NO_X emissions. <u>An Oxidation catalyst system combined with DLN combustion technology reduces CO and VOC.</u>

<u>Specific Condition III.A.2 - Combined Cycle Gas Turbine</u>: The permittee is authorized to install, tune, maintain and operate a new combined cycle unit consisting of a General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set. The combined cycle unit shall be designed as a system to generate a nominal 175 MW of shaft-driven electrical power and less than 75 MW of steam-generated electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a single exhaust stack that is 135 feet tall and 19.0 feet in diameter, and associated support equipment. ~~A separate bypass stack and damper may be installed to facilitate startup of the steam cycle while operating the combustion turbine in Low Emissions Modes 5, 5Q, and 6Q.~~ [Applicant Request; Design]

<u>Specific Condition III.A.8 - Power Augmentation</u>: As an alternate method of operation, the permittee may inject steam into the combined cycle gas turbine for power augmentation. ~~Power augmentation is permitted 2000 hours per 12-consecutive months and is not limited if oxidation catalyst is installed. The 2000 hour limit may be revised at the request of the applicant based upon review of actual performance and control equipment cost-effectiveness following proper public notice.~~
~~[Rule 62-212.400 (BACT), F.A.C.]~~

<u>Specific Condition III.A.11 - Carbon Monoxide (CO);</u>

a. *Initial Test, Standard Operation:* When not operating in the power augmentation mode, CO emissions shall not exceed <u>9.7</u> ~~31.0~~ pounds per hour nor <u>2.5</u> ~~8.0~~ ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

b. *Continuous Compliance, Standard Operation:* When not operating in the power augmentation mode, CO emissions shall not exceed <u>2.5</u> ~~8.0~~ ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system.

c. *Initial Test, Power Augmentation*: When injecting steam for power augmentation and a compressor inlet temperature of 59° F, CO emissions shall not exceed 16.1 ~~48.0~~ pounds per hour nor 4 ~~12.0~~ ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

d. *Continuous Compliance, Power Augmentation*: When injecting steam for power augmentation, CO emissions shall not exceed 4.0 ~~12.0~~ ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system.
[Rule 62-212.400(BACT), F.A.C.]

Section III.A.16 – Volatile Organic Compounds (VOC): The efficient combustion of clean fuels and good operating practices for the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the fuel specification and CO standards shall serve as indicators of good combustion. {Permitting Note: VOC emissions are expected to be less than 2.4 ~~3.0~~ pounds per hour and 1.1 ~~1.3~~ ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-4.070(3), F.A.C.]

Specific Condition III.A.17 - Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of the combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

b. *Work Practice BACT*: ~~The unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire~~. A damper shall be installed on the HRSG stack to minimize the frequency of cold and warm starts. An oxidation catalyst control system shall be installed to reduce excess emissions occurring during startups, shutdowns, and malfunctions. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following procurement of the HRSG.
c. *Low-Load Restriction*: Except for startup and shutdown, operation ~~under DLN Modes 1, 2, 3, and 4~~ below 50 percent is prohibited.

Specific Condition III.B.13 - Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of the simple cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

c. *Low-Load Restriction*: Except for startup and shutdown, operation ~~under DLN Modes 1, 2, 3, and 4~~ below 50 percent is prohibited.

In reference to Condition III.A.20, El Paso submitted the following comment: "The procedure for determining NO_X compliance when data is missing or excluded appears to differ than the procedure described in Condition 20.a. for CO compliance. Clarification of these CEM compliance procedures is requested from the Department".

Department Response:

The Department agrees with El Paso and clarifies the mentioned condition as follows:

Specific Condition III.A.20 - CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. The CEM systems shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C.

a. Compliance with the continuous CO emissions standards shall be based on a 3-hour block average starting at midnight of each operating day. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. If a unit operates less than 3 hours during the block, the 3-hour block average shall be the average of available valid hourly average emission rate values for the 3-hour block. The CO monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. For purposes of determining compliance with the CEM emission standards of this permit, missing or excluded data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour block average for

CO. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding CO emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

Additional Department Clarifications of Permit Conditions

Based on comments received and petitions filed for several projects in Broward County, the Department reviewed the Emission Unit exemptions at Section 62-210.300, F.A.C. The Department's position is that the units mentioned in Section III.D.1-6 are not exempt from permitting and that they should be considered under the facility BACT determinations for each pollutant.

The affected units were already included in the permit. The conditions are revised as follows:

Section III D – Other Emission Units

1. Cooling Tower: BACT for the Cooling Tower was determined to be the use of fresh water and drift eliminators designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. A not to exceed limit of 4200 mg/l total dissolved solids shall be maintained within the cooling tower. {Permitting Note: Potential emissions in tons per year are expected to be less than 1.64 for PM and 0.99 for PM_{10}}.
[Rule 62-212.400 (5) (c) F.A.C., BACT determination].

2. 2600 HP Diesel Generator: ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)20. F.A.C., provided that fuel oil use does not exceed 32,000 gallons per year.~~ The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.12 for PM, 3.26 for NOx, 0.73 for CO, 0.07 for SO_2 and 0.18 for TOC (total organic carbons)}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

3. 12.8 MMBtu/hr Gas-fired Natural Gas Fuel Heater: ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)2 F.A.C., Categorical Exemptions.~~ This unit is subject to applicable provisions of 40 CFR 60, Subpart Dc. New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

4. 250 HP Diesel Fire Pump: ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)21 F.A.C., Categorical Permit Exemptions.~~ The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.013 for PM, 0.74 for NO_X, 0.18 for CO, 0.0014 for SO_2 and 0.08 for TOC (total organic carbons)}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

5. Aqueous Ammonia Storage Tank: This unit will contain less than a 20 percent concentration of aqueous ammonia by volume and therefore is not subject to applicable provisions of 40 CFR 68, Chemical Accident Provisions. [Rule 62-4.070 (3) F.A.C.]

6. Two Diesel Fuel Storage Tanks (each less than 1000 gallons): ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(b)(iv) F.A.C., Generic and Temporary Exemptions.~~ This unit shall store 0.05% or less sulfur diesel fuel (by weight). [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

Manatee County Environmental Management Department (MCEMD) Comments:

MCEMD Comment 1: *"The proposed facility has been determined to be a major source of air pollution, since emissions of at least one regulated air pollutant (particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide or volatile organic compounds) exceeds 100 tons per year (TPY). The Department's technical evaluation and preliminary determination is that "emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standard".*

The new federal standard for ozone has been established at a level equivalent to 85 ppb averaged over any 8-hour period. An area will be considered non-attainment if the average of the annual fourth highest ozone readings at a monitoring site for any three year period equals or exceeds 85 ppb. Based on DEP's monitoring data, the three year running average for ozone within Manatee County has been steadily increasing. Considering that the County is marginally meeting the ozone standard and, that the neighboring counties of Sarasota and Hillsborough have already exceeded the standard for years 1999-2001, Manatee County does not concur with the Department's evaluation that the facility will not cause or contribute to violation of ambient air quality standards".

Please provide any additional information that will confirm the Department's position that these air quality standards will not be exceeded".

Department Response: The Department is confident that the proposed NO_X and VOC increases at the El Paso facility will not interfere with the Tampa Bay areawide strategy for reducing ozone concentrations. Ozone is an areawide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

Based on recent monitoring data, the Tampa Bay area is marginally out of attainment of the 8-hour ozone standard. The area is still classified by EPA as in attainment. The Department will need to address this situation by requiring sufficient areawide reductions of NO_X and/or VOC to bring the area into compliance. Although the regulatory process is delayed because of court challenges to the 8-hour standard, the Department can identify a number of existing requirements that will significantly reduce ozone precursors in the Tampa Bay area. These requirements include the massive NO_X reductions from the TECO Order, low sulfur gasoline (low sulfur gasoline reduces NO_X emissions in cars and trucks), low sulfur diesel fuel, and more restrictive new car and truck emissions (Tier II standards).

In total, these reductions (mostly of NO_X) amount to tens of thousand tons per year or more over the next decade. The NO_X (365 tons per year) and VOC (29 tons per year) emissions increases from the proposed El Paso facility would not significantly reduce the total areawide reductions expected in the future. In fact, an argument can be made that the operation of the more efficient El Paso facility would result in further decreases in areawide emissions to the extent that even a small amount of power from higher polluting facilities is offset with power generated by the El Paso facility.

To more conclusively "prove" that the 365 tons of NO_X and 29 tons of VOC will not cause or contribute to a violation a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. Variations of the input from El Paso (from 0 to 365 TPY of NO_X, and 0 to 29 TPY of VOC) would not make any appreciable difference in the results. The uncertainty in any regional ozone model would be much greater than any contribution from this project.

Interestingly, emissions of NO_X from the El Paso project are primarily NO that tends to reduce ozone on a very localized basis. As the NO transforms to NO_2 miles downwind, it tends to increase ozone.

Variations in the emissions from the major conventional plants would make a difference. The reductions of 50,000 to 100,000 of NO_X caused by the Clean Air Act, the Department's Consent Decree, repowering of some conventional units, and competition from cleaner units will reduce the contribution of power plants to violations of the NAAQS in the Tampa Bay area. These reductions are about three orders of magnitude greater than the increase from the El Paso project. As previously discussed, the El Paso project will probably cause at least some further modest reduction in the region, based on displacement of some existing power with cleaner power.

MCEMD Comment 2 *"The design for the proposed facility includes a steam turbine generator and an unfired heat recovery steam generator capable of a maximum of 120MW. According to Chapter 403.503, F.S., steam or solar electrical generating facilities of less than* ***75 megawatts*** *[emphasis added] is exempt from the criteria under the Florida Electrical Power Plant Siting Act. What control systems will be used to ensure that the 75 MW threshold is not exceeded?"*

Department Response: The Department required from El Paso a clear description of the manner by which electrical power from the steam turbine-electrical generator will be limited to less than 75 MW. Therefore, on the June 26, 2001, El Paso's letter in response to the Department's request for additional information stated the following:

"The steam turbine electrical generator (STG) planned for the Manatee Energy Center (BEC) combined cycle (CC) unit will have a maximum generating capacity of 120 megawatts (MW). The CC unit will have a modern distributed control system (DCS) that will serve as a means to control STG operation utilizing plant instrumentation and equipment. In conjunction with the steam turbine governor, a control management system will be implemented that will limit the STG output to less than 75 MW. The power output of the STG will be recorded on the plant DCS for records purposes and reporting needs as required. The CC unit will feature hardware provisions that will allow diversion of steam produced by the heat recovery steam generator (HRSG) from the STG thereby limiting its output. The main hardware features that will limit STG electrical output include CTG steam mass augmentation, STG controls, and a STG steam bypass system. Each of the systems is described in the following sections.

"The CC unit CTG will incorporate steam injection nozzles and design features that will allow a portion of the high-pressure steam generated by the HRSG to be diverted from the STG to the CTG. This introduction of steam to the CTG allows for a mass flow enhancement. The increased mass flow that results from steam injection will increase CTG output as well as fuel consumption. At ambient temperatures of about 50°F or less, steam mass flow augmentation will be limited by CTG equipment limitations. For instance, CTG backpressures could increase to levels beyond those recommended by the vendor. At these colder ambient temperature conditions, steam injection into the CTG will be curtailed and alternate means of steam diversion from the STG will be called on to a greater extent.

"The specifics of the limitations on CTG steam injection will be developed by the CTG vendor. Additionally, the specifics of steam introduction will be developed in conjunction with the CTG control systems for proper coordination with the Dry Low-NO_X (DLN) combustor control algorithms.

"Steam flow to the CTG steam injection nozzles, including CTG control integration, will be controlled from a signal generated within the DCS. This control signal will operate a control valve that regulates steam flow by modulation of the valve seat or opening area thereby allowing steam flow modulation.

"Steam flow to the CTG injection nozzles will be measured with classical steam flow measurement devices such as an orifice plate or an annubar. The steam flow measurement device will have a differential pressure transmitter attached to pressure sensing lines that will monitor the process and produce a proportional 4-20 milliamp (ma) signal that will tie in to the plant DCS. This signal will be converted to flow and signals will be transmitted to the CTG combustion control systems as well as to the balance of the plant DCS. During base load operations, the steam flow to the CTG injection nozzles will likely be a fixed steam mass flow or fixed percent of CTG mass flow. Injection of steam will occur at 100 percent load only. During upsets/startups and conditions such as low ambient temperatures, the steam flow will be controlled to coordinate with CTG combustion control to allow stable operation and avoid surge and stall within the CTG. During these periods, alternate STG steam diversion paths will be used.

"The STG will be fitted with an electronic governor and control system that will control the steam flow into the STG and hence the STG electrical output. Additional instrumentation will be used to adjust this control loop. For instance, condenser back pressure, intermediate pressure and low pressure steam flows, steam temperatures and pressure will each have a significant impact on the determination of the proper steam flow to the STG.

"The primary measurement of STG electrical output will be the main input to the STG governor control loops. This power measurement will be feed to the STG governor to compare to the primary set point. As an example, the primary set point may have a value of 74.9 MW. Following control system tuning, the set point will be adjusted to allow for control swings and upsets such that the hourly STG electrical production average will never exceed 75 MW.

"Whenever steam to the CTG injection nozzles and to all other locations are not sufficient to reduce STG output to the set point, the primary means of final control will be a STG steam bypass system. The STG steam bypass system will allow steam flow from the HRSG to bypass the STG and "dump" directly into the condenser. The DCS will generate a final control signal that will modulate this steam dump. A CC plant typically includes this hardware to allow for steam dumping during upsets or malfunctions. Additional control signals and associated hardware will regulate this dump steam as the final means of disposal of excess HRSG steam. In addition, an economizer bypass system may be used to reduce the flow of water passing through the economizer stage of the HRSG, which will reduce the flow-of steam produced.

"The control systems described above will typically scan each instrument every second and recalculate and update the status and driving signals going to each field device. Following control system tuning, the control systems will regulate STG output to the required level".

MCEMD Comment 2: *"The proposed facility will employ cooling towers for the purpose of cooling and condensing steam. Much of this cooling water is evaporated and must be replaced. According to the Southwest Florida Water Management District (SWFWMD), the proposed location of the facility is within the Most Impacted Area (MIA) which prohibits the permitting of new groundwater withdrawals. Please provide details as to the source and quality of water to be used at the facility".*

Department Response:

The Manatee Energy Center plans to use reclaimed water provided by the City of Bradenton Water Reclamation Facility (El Paso's e-mail dated December 3, 2001).

MCEMD Comment 3: *"How will this new supplier of electrical energy interact with the current regional suppliers? Will this facility displace energy being supplied these existing facilities? Does this facility have a local client base or will the energy be transmitted outside the region? Will a "needs determination" evaluation be conducted? Due to the fact that Manatee County is marginally meeting the current ozone standard, we would support an offset or pollutant trading so that the development of this facility would not cause a net increase in air emissions.*

Department Response

A "Need" determination pursuant to Sections 403.501-518, Florida Power Plant Siting Act is outside of the authority of the Department. The project was reviewed by the Department in accordance with the air permitting regulations applicable to projects are exempt from the Act.

The Department already concluded that emissions from the facility would not cause or contribute to a violation of the ozone standard. The Department also believes that the project will tend to reduce emissions in the Tampa Bay area if it displaces even 1 megawatt from conventional plants for every 10 megawatts that it generates. The plan proposed by MCEMD cannot be implemented unilaterally by the Department and certainly not by the time the Department is required to act on the El Paso.

Attachment I is a response from El Paso to the County's comments. The Department does not necessarily agree or disagree with the explanation provided by El Paso, but appreciates the effort to answer the County's questions.

MCEMD Comment 4: *"The Tampa Bay Estuary Program (TBEP) is charged with ensuring that Bay conditions are protected and in some instances improved. The TBEP determined that excessive nitrogen loading to the Bay is of special concern. This nutrient causes algal blooms, decreased water clarity and generally degrades water quality, resulting in habitat and fisheries losses. Recent studies indicate that at least 29 percent of the Bay's total nitrogen load is from atmospheric deposition. Due to the proximity to the Bay and Terra Ceia Aquatic Preserve, it is essential that the applicant provide detailed information on expected depositional impacts from nitrogen components (NO_X and ammonia) and other pollutants, along with their plans to offset these impacts in order to meet the TBEP's goal of "holding the line" on pollutant inputs to the Bay. Why couldn't Best Available Control Technology (BACT) be replaced with Maximum Available Control Technology (MACT) in this sensitive area? For example, $SCONO_X$ is considered to be a better control device and does not contribute bio-available ammonia through "ammonia slip". Can the Department require MACT for facilities located in sensitive areas?"*

Department Response:

As previously mentioned, the Department concluded that emissions to the atmosphere will be relatively low and that impacts on ambient air are less than significant. The Department does not dispute the assertions regarding deposition into the Bay. However a systematic approach that implements Clean Air Act requirements, promotes repowering, enforces on polluters, and encourages clean projects will hold the line and actually improve Tampa Bay.

The Department determined that MACT is not applicable because the facility will emit less than 10 tons per year of any hazardous air pollutant (HAP). The EPA has advised that MACT for certain types of combustion turbines (such as the GE 7FA) will likely be the use of Dry Low NO_X (DLN) technology. For certain other types of turbines, MACT will be the use of oxidation catalyst.

The Department notes that MACT for hazardous air pollutants (HAPs) is typically less stringent than BACT for PSD pollutants. However, the Department notes that DLN technology will be installed on the simple cycle units and both DLN and oxidation catalyst will be installed on the combined cycle unit.

Please refer to the enclosed BACT determination. The Department considered $SCONO_X$, but found that it is not technically feasible on the simple cycle units. It is not cost-effective on the combined cycle unit.

El Paso reviewed the County's comment and replied as follows: "Based on the use of reclaim water currently discharged to Tampa Bay, operation of the Manatee Energy Center will result in a net decrease in total nitrogen loading to Tampa Bay. Reclaim water used by the Manatee Energy Center will be managed such that surface discharges to Tampa Bay will not occur".

El Paso also stated that "a report evaluating nitrogen loading on Tampa Bay due to operation of the Manatee Energy Center is being prepared and will be provided to the Department when available". The Department does not necessarily agree or disagree with El Paso's assessment of this issue, but is appreciative of the effort made in responding to the County's comment. The Department will provide a copy of the future El Paso report.

MCEMD Comment 5: *"Although the proposal is for a predominantly gas-fired power plant, the permit would allow combustion of diesel fuel in a 2600 HP diesel-fired electric generator and a 250HP diesel water pump. The hourly emissions of criteria pollutants would be significantly greater. We question whether these increased emissions from the use of diesel fuel is acceptable in terms of cumulative effects of other regional and in-County sources?"*

Department Response:

It is anticipated that each of these units will consume less than 32,000 gallons per year which would normally make them exempt from permitting if they were constructed at existing facilities. The No. 2 distillate fuel oil used for this project will have a maximum 0.05 percent sulfur specification and will be used only for these small units. This compares with the maximum limit set by Manatee County for fuel sulfur of 1 percent (Manatee County Code of Ordinances – Section 1-32-5(d)).

As stated previously, the 2600 HP Emergency Generator potential emissions in tons per year are expected to be less than 0.12 for PM, 3.26 for NO_X, 0.73 for CO, 0.07 for SO_2 and 0.18 for TOC (total organic carbons). Emissions from the 250 HP Fire Water Pump Diesel Engine emissions in tons per year are expected to be less than 0.013 for PM, 0.74 for NO_X, 0.18 for CO, 0.0014 for SO_2 and 0.08 for TOC.

With the very low emissions and the likelihood of (passively) offsetting even some power from nearby conventional units, it is clear that the project as designed is acceptable "in terms of cumulative effects of other regional and in-county sources."

MCEMD Comment 6 : *"In several sections, the permit requires that reports and notifications be submitted to the Department of Environmental Protection. We would ask that the Manatee County Environmental Management Department also is listed as a recipient of such reports, documents, and notifications, according to the same time frames required for submittal the Department".*

Department Response:

The Department will review and revise the permit to include the Manatee County Environmental Management Department as a recipient of the various documents, reports and notifications.

Environmental Protection Agency (EPA) Comments

Many of EPA's comments are favorable critiques of the Department's approach in preparing the draft permit and BACT determination. Following are certain EPA comments that the Department has determined require clarification or a response.

EPA Comment 4 - Oxidation Catalysis: "The draft permit CO emission limit of 8 ppmvd for the simple cycle combustion turbines and for the combined cycle combustion turbine when not operating in power augmentation mode is among the lower BACT limits established in Region 4 for combustion turbines. We further understand Florida Department of Environmental Protection's (FDEP) expectation that the turbines will in fact typically operate with even lower emissions based on inherent combustor design and good combustion practices alone. However, please note that the use of catalytic oxidation for further control of combustion turbine CO emissions, especially for combined cycle combustion turbines, has become much more common as part of BACT determinations for combustion turbine projects.

Catalytic oxidation has the added advantage of controlling volatile organic compound (VOC) emissions including volatile organic hazardous air pollutants

Further related to the CO draft permit emission limit of 8 ppmvd, we note that Appendix BD (the BACT determination) indicates an emission rate of 7.4 ppmvd at full load for either combined cycle or simple cycle combustion turbines. Based on our understanding that the draft permit has precedence over Appendix BD, we presume that 8 ppmvd will be the enforceable limit.

Emissions of CO from combustion turbines increase sharply below a certain load level (unless an add-on control device is in use). For GE 7FA combustion turbines, this sharp increase occurs with operation below about a 50-percent load level. It is not clear to us that the draft permit restricts normal operation (that is, operation other than during startup and shutdown) to load levels of 50 percent and higher. Condition A.17.c. prohibits operation of the combined cycle combustion turbine at "DLN Modes 1, 2, 3, and 4" (except during startup and shutdown), and Condition B.13.c. specifies a similar restriction for the simple cycle combustion turbines. Since the load levels equivalent to these modes are not specifically stated, however, we are not certain what load levels are prohibited. Furthermore, we would appreciate your identifying which monitoring requirements in the draft permit serve to track compliance with the low-load restrictions.

Department Response: In their application, El Paso, submitted cost-effectiveness calculations to control CO emissions by oxidation catalyst. Based on the most conservative case the calculations result in an oxidation catalyst cost estimate of $2,475 per ton of CO removed (combined cycle operation) and $8,981 (simple cycle operation). The Department does not consider oxidation catalyst to be cost-effective for simple cycle operation based on these calculations.

El Paso's cost effectiveness calculations are based on reduction of CO concentrations from the range of 11.7 to 1.2 ppmvd under combined cycle (steam power augmentation mode) and from 7.4 to 0.7 ppmvd under simple cycle operation. Based on data available to the Department, actual emissions without oxidation catalyst are on the order of 1 ppmvd while firing gas or fuel oil at least under normal modes of operation (not steam power augmentation). This is substantially less than even the objective by oxidation catalyst.

The Department has actual no data on CO emissions during steam power augmentation and initially limited operation under this mode to 2000 hours per year. However as discussed in the first comment by El Paso on Page 1, the company will install oxidation catalyst on the combined cycle unit and the Department will reduce CO emission limits while allowing continuous operation under steam power augmentation mode. This will also reduce VOC and HAP emissions. A CO monitor will be installed on the combined cycle unit.

The Department believes that with SCR and oxidation catalyst, there is less reason to limit operations to less than 50 percent of full load. However, El Paso has agreed to a condition that operation at loads less than 50 percent is not allowed except during startup and shutdown.

Startup under simple cycle operation will be short (less than 15 minutes), while emissions under full load operation will be very low even without oxidation catalyst. The Department will require El Paso to install a CO monitor at the El Paso Broward to collect information regarding CO emissions during simple cycle startup and shutdown. The data may be used to set startup limitations at future projects.

EPA Comment 5 - Startup and Shutdown Data Inclusion and Exclusion: "*As we have often commented, startup and shutdown are part of normal combustion turbine operation and need to be addressed in PSD permits. FDEP has done so for this project by establishing a work practice standard and by limiting the number of hours of emissions that can be excluded from* NO_X *and CO compliance demonstrations for the combined cycle combustion turbine and from* NO_X *compliance demonstration for the simple cycle combustion turbines. Other permit options that could be considered include limitations on the number of startups and shutdowns in any 12-month period; mass emission limits for* NO_X *and CO emissions during any 24-hour period to include emissions during startup and shutdown; and future establishment of startup and shutdown BACT emission limits for* NO_X *and CO derived from test results during the first few months of commercial operation. In addition, compliance with any explicit or implicit annual emissions limits should be assessed with startup and shutdown emissions included. Regarding the option of mass emission limits, we acknowledge FDEP's comments that such limits may be difficult to quantify.*

"*The only definition of startup that we find is in Appendix BD of the package. As mentioned previously, we understand that the provisions of Appendix BD are not necessarily enforceable. Furthermore, the definition in Appendix BD denotes when startup commences but does not state the operating level or other characteristic marking the end of startup and the beginning of normal operation. We recommend that a more complete definition be developed so that the emission measurements eligible for exclusion under the excess emissions provisions can be confirmed easily.*

"*Conditions 17d of the combined cycle section and 13d of the simple cycle section contain provisions allowing certain data during periods of startup and shutdown to be excluded from compliance demonstrations". Condition 17d for the combined cycle combustion turbine exempts up to 2 hourly emission rate values in a calendar day, except for combined cycle cold startups, in which case up to 4 hourly emission rate values in a calendar day can be exempted. Additionally, Condition 17d indicates that no more than a total of 4 hourly emission rate values shall be exempted in a calendar day. It is unclear to us the purpose of the latter restriction on total hourly emission rate values. Also, it should be clarified in what case a total of 4 hours can be exempted when there is no combined cycle cold startup during the calendar day.*

"*Condition 13d for the simple cycle combustion turbines exempts "no more than 2 hourly emission rate values" from the* NO_X *compliance demonstration as well as restricting the exemption to "no more than a total of 3 hourly emission rate values" in a calendar day. The purpose of the latter restriction is unclear, since the* NO_X *compliance period is a 24-hour block average. Finally, to remain consistent with previous FDEP simple cycle combustion turbine permits, no more than 2 hours out of a 24-hour period (or calendar day) should be exempted from compliance demonstrations".*

Department Response: The Department does not allow extended operation at low loads for the simple cycle units during which higher emissions typically occur. Startup for the simple cycle units is simply the time it takes to reach DLN Mode 5Q (roughly corresponds to 50 percent of full load). The Work Practice BACT requires that this mode be reached within 15 minutes. Both emissions and the DLN Modes are tracked by the Mark VI control system.

General Electric did not agree with the Department's Work Practice BACT to minimize startup time of the combined cycle unit (i.e. time to achieve Mode 5Q). El Paso proposed the alternative of installing oxidation catalyst for CO and VOC reduction. The facility must also employ good operating practices during periods of excess emissions. This includes, for example, operation of the SCR system on the combined cycle unit as soon and for as long as the temperature conditions within the heat recovery steam generator allow.

The Department believes that the measures described (in addition to exclusive firing of natural gas) will result in the lowest emissions (whether in startup or steady state modes) from any combined or simple cycle projects permitted in the Southeast.

The Department has been progressively implementing EPA's comments regarding startups, high emission modes, inclusion and exclusion of data, etc. The present permit represents a major effort in this regard. Further efforts will be made as emissions data are received from facilities required to demonstrate compliance with NO_X and CO limits by CEMS.

The following sentence of Specific Condition 13.d. for the simple cycle turbines was revised as suggested: " No more than a total of two ~~three~~ hourly average emission rate values shall be excluded from the continuous NO_X compliance demonstrations for such periods in any calendar day".

EPA Comment 6 - Initial and Annual Testing: "Draft permit Condition 14 pertaining to simple cycle combustion turbines requires testing initially and at permit renewal for PM/PM_{10}, CO, NO_X, and VOC. The draft permit conditions for the combined cycle combustion turbine do not require PM/PM_{10} and VOC initial and renewal testing. We have agreed with FDEP in the past that PM/PM_{10} and VOC testing is not required for combined cycle combustion turbines with continuous emission monitoring systems (CEMS) for CO. However, a permit for a project with both combined cycle and simple cycle combustion turbines that has different initial and renewal testing requirements for the two types of turbines may be perceived as inconsistent. On a related point, we recommend that FDEP give consideration to requiring CO CEMS for the simple cycle combustion turbines as well as for the combined cycle combustion turbine in view of the fact that the simple cycle combustion turbines will be allowed to operate up 5,000 hours per year at full load (and even more hours at a combination of full and partial loads)".

Department Response: The Department agrees with EPA and revises these conditions to include initial and renewal testing for PM/PM_{10} and VOC emissions for all turbines. The Department will require El Paso to install a CO monitor at the El Paso Broward to collect information regarding CO emissions during the very short simple cycle startup and shutdown periods. The data may be used to set startup limitations at future projects. The Department notes that after the startup period, emissions will be approximately 1 - 2 ppmvd (although the limit is 7.4 ppmvd) based on actual test data. The continuous collection of CO data at all simple cycle units does not appear justified except at those that exhibit inherently higher emissions than the GE 7FA.

EPA Comment 7- Pipeline Natural Gas: "The term "pipeline-quality natural gas" appears several times in the draft permit. We have sought in the past for a government agency or industry trade group definition of "pipeline-quality" and have never succeeded in finding such a definition. We presume that the term "pipeline-quality natural gas" means natural gas obtained from an intrastate or interstate commercial natural gas pipeline."

Department Response: The Department confirms that such gas is obtained from a FERC-regulated natural gas pipeline.

EPA Comment 8 - Ammonia Emissions: "The draft permit contains an emission limit for ammonia of 5 ppmvd. Ammonia is not regulated under the PSD program, and we do not have a definitive policy on ammonia emissions. However, we can comment that the limit in the draft permit is consistent with (although not equal to the lowest) ammonia limits we are aware of from projects outside Region 4."

EPA Comment 9 - Air Quality Impact:: "In the air quality impact evaluations prepared for this project, we see no acknowledgment that NO_X emissions are precursors to ground-level ozone formation. Such acknowledgment would help demonstrate why control of NO_X emissions from combustion turbines is important".

Department Response:

The Department certainly acknowledges that NO_X emissions and VOC emissions are the key precursors in the formation of ground-level ozone.

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

El Paso Merchant Energy Company
1001 Louisiana Street
Houston, TX 77002

Authorized Representative:
William Mack, Sr., Managing Director

Facility Name:	Manatee Energy Center
Project No.	0810199-001-AC
Air Permit No.	PSD-FL-318
Facility ID No.	0810199
SIC No.	4911
Expires:	December 1, 2004

PROJECT AND LOCATION

This permit authorizes the construction of a new nominal 600-megawatt electrical generating plant, the Manatee Energy Center, to be located 1 mile northeast of Buckeye Road and US Highway 41 near Piney Point in Manatee County. UTM coordinates are: Zone 17; 349.1 km East; 3057.6.0 km North. The plant will consist of one combined cycle gas turbine, two simple cycle gas turbines, and associated equipment.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Howard L. Rhodes
1/16/02

Howard L. Rhodes, Director
Division of Air Resources Management
(Date)

FACILITY DESCRIPTION

The proposed project is for a new electrical power plant, the Manatee Energy Center, which will generate a nominal 600 MW of electricity. The plant will consist of one combined cycle gas turbine unit (250 MW, total) and two simple cycle gas turbine units (175 MW, each).

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
001	**Combined Cycle Unit No. CC-1** consists of a natural gas fired 175 MW General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator, and a separate steam turbine-electrical generator.
002	**Simple Cycle Unit No. SC-1** consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.
003	**Simple Cycle Unit No. SC-2** consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.
004	**Cooling Tower** consisting of one 5-cell freshwater mechanical draft freshwater cooling tower.
005	**Other Emissions Units** include one 2600-hp diesel generator, one 250-hp diesel fire pump, a 12.8 MMBtu/hr (HHV) gas-fired fuel heater, an aqueous ammonia storage tank, and small diesel storage tanks.

REGULATORY CLASSIFICATION

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new gas turbines are subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the new facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: The new gas turbines are subject to the New Source Performance Standards of 40 CFR 60, Subpart GG. The gas fired fuel heater is subject to the New Source Performance Standards of 40 CFR 60, Subpart Dc.

NESHAP: No emission units are identified as being subject to a National Emissions Standards for Hazardous Air Pollutants (NESHAP).

SITING: The project is not subject to Section 403.501-518, F.S., Florida Electrical Power Plant Siting Act, based on information regarding gross electrical power generated from the steam (Rankine) cycle submitted by the applicant and reviewed by the Department.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.

COMPLIANCE AUTHORITIES

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the DEP Southwest District Office, 3804 Coconut Palm Dr, Tampa, Fl 33619-8218. Copies of all such documents shall be submitted to the Air Section of the Manatee County Environmental Management Department, 202 Sixth Avenue East, Bradenton, Florida 34208.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

Appendix XS. Continuous Monitor Systems Semi-Annual Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on 03/28/01 and all related completeness correspondence.
- Draft permit package issued on 09/11/01
- Comments received from the public, the applicant, the EPA Region 4 Office, and the National Park Service.

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

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

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

4. Completion of Construction: The permit expiration date is December 1, 2004. Physical construction shall be completed by September 1, 2004. The additional time provides for testing, submittal of results, and submittal of the Title V permit application to the Department.

5. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

6. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

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

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

9. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

10. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and copies to each Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

This section of the permit addresses the following new emissions unit.

Emissions Unit 001: Combined Cycle Gas Turbine No. CC-1
Description: The combined cycle unit consists of a General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW, an unfired heat recovery steam generator (HRSG), and a separate steam turbine-electrical generator set. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, and an evaporative inlet air-cooling system.   *Fuel*: The combined cycle unit is fired exclusively with pipeline-quality natural gas.   *Capacity*: At a compressor inlet air temperature of 35° F, the combined cycle gas turbine produces approximately 180 MW when firing approximately 1700 MMBtu (LHV) per hour of natural gas.   *Controls*: The efficient combustion of pipeline-quality natural gas at high temperatures minimizes emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. A selective catalytic reduction (SCR) system combined with Dry Low-NO_X (DLN) combustion technology reduces NO_X emissions. An oxidation catalyst system combined with DLN combustion technology reduces CO and VOC.   *Stack Parameters*: When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit a 135 feet tall stack that is 19.0 feet in diameter with a flow rate of approximately 1,040,000 acfm at 187° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions standards specified for this unit represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

EQUIPMENT

2. Combined Cycle Gas Turbine: The permittee is authorized to install, tune, maintain and operate a new combined cycle unit consisting of a General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set. The combined cycle unit shall be designed as a system to generate a nominal 175 MW of shaft-driven electrical power and less than 75 MW of steam-generated electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a single exhaust stack that is 135 feet tall and 19.0 feet in diameter, and associated support equipment. [Applicant Request; Design]

3. DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric DLN-2.6 combustion system to control NO_X emissions from the combined cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NO_X emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
[Design; Rule 62-212.400(BACT), F.A.C.]

4. (SCR) System: The permittee shall install, tune, maintain and operate a selective catalytic reduction (SCR) system to control NOx emissions from the combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, and electrical, piping and other auxiliary equipment. The SCR system shall be designed to reduce NO_X emissions and ammonia slip below the permitted levels. [Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

5. Permitted Capacity: The maximum heat input rate to the combined cycle gas turbine shall not exceed 1742 MMBtu per hour based on a compressor inlet air temperature of 35° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

6. Authorized Fuel: The combined cycle gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

7. Restricted Operation: The hours of operation for the combined cycle gas turbine are not limited (8760 hours per year). [Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

8. Power Augmentation: As an alternate method of operation, the permittee may inject steam into the combined cycle gas turbine for power augmentation. [Rule 62-212.400 (BACT), F.A.C.]

9. Power Generated Limitation: Electrical power from the steam-electrical generator shall be limited to 74.9 MW (gross) on an hourly basis. The owner or operator shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system. [Applicant Request]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to the combined cycle gas turbine. Unless otherwise noted, the mass emission limits are based a compressor inlet temperature of 35° F and 100% load. For comparison to the standard, actual measured concentrations shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

10. Ammonia Slip: Ammonia slip shall not exceed 5 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method CTM-027. [Rule 62-4.070(3), F.A.C.]

11. Carbon Monoxide (CO)

    a. *Initial Test, Standard Operation*: When not operating in the power augmentation mode, CO emissions shall not exceed 9.7 pounds per hour nor 2.5 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

    b. *Continuous Compliance, Standard Operation*: When not operating in the power augmentation mode, CO emissions shall not exceed 2.5 ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system.

    c. *Initial Test, Power Augmentation*: When injecting steam for power augmentation and a compressor inlet temperature of 59° F, CO emissions shall not exceed 16.1 pounds per hour nor 4 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

d. *Continuous Compliance, Power Augmentation*: When injecting steam for power augmentation, CO emissions shall not exceed 4 ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system. [Rule 62-212.400(BACT), F.A.C.]

12. Nitrogen Oxides (NO_X)

a. *Initial Test*: NO_X emissions shall not exceed 17.0 pounds per hour nor 2.5 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method 7E.

b. *Continuous Compliance*: NO_X emissions shall not exceed 2.5 ppmvd corrected to 15% oxygen based on a 24-hour block average as determined by valid data collected from the certified CEM system.

NO_X emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

13. Particulate Matter (PM/PM_{10}): The fuel specifications established in Condition No. 6 of this section combined with the efficient combustion design and operation of the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. {Permitting Note: Particulate matter emissions are expected to be less than 11 pounds per hour as determined by EPA Method 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]

14. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2): The fuel sulfur specification established in Condition No. 6 of this section effectively limits the potential emissions of SAM and SO_2 from the combined cycle gas turbine. Compliance with the fuel sulfur specification shall be demonstrated by the sampling, analysis, record keeping and reporting requirements established in Section III.C of this permit. [Rule 62-212.400(BACT), F.A.C.]

15. Visible Emissions: As determined by EPA Method 9, visible emissions shall not exceed 10% opacity based on a 6-minute average. Except as allowed by Condition No. 17 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

16. Volatile Organic Compounds (VOC): The efficient combustion of clean fuels and good operating practices for the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the fuel specification and CO standards shall serve as indicators of good combustion. {Permitting Note: VOC emissions are expected to be less than 2.4 pounds per hour and 1.1 ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of the combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.

b. *Work Practice BACT*: A damper shall be installed on the HRSG stack to minimize the frequency of cold and warm starts. An oxidation catalyst control system shall be installed to reduce excess emissions occurring during startups, shutdowns, and malfunctions. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following procurement of the HRSG.

c. *Low-Load Restriction*: Except for startup and shutdown, operation below 50 percent is prohibited.

d. *CEM System Data Exclusion*: Except for combined cycle cold startups, no more than two hourly average emission rate values in a calendar day shall be excluded from the continuous NO_X and CO compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than four hourly average emission rate values in a calendar day shall be excluded from the continuous NO_X and CO compliance demonstrations due to combined cycle cold startups. No more than a total of four hourly average emission rate values shall be excluded from the continuous NO_X and CO compliance demonstrations for all such episodes in any calendar day. A "*combined cycle cold startup*" is defined as startup after the combined cycle gas turbine has been shutdown for 48 hours or more. A "*documented unavoidable malfunction*" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

[Design; Rules 62-4.070(3), 62-4.130, 62-210.700, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{Permitting Note: Performance test methods are specified in Gas Turbine Common Conditions, Section III.C.}

18. Initial Compliance Tests: The combined cycle gas turbine shall be tested initially and upon permit renewal to demonstrate compliance with the emission standards for CO, NO_X, PM/PM_{10}, VOC visible emissions and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of the combined cycle gas turbine. With appropriate flow measurements, certified CEM system data may be used to demonstrate compliance with the CO and NO_X standards. NO_X emissions recorded by the CEM system shall be reported for each ammonia slip test run.
[Rule 62-297.310(7)(a)1., F.A.C.]

19. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the combined cycle gas turbine shall be tested to demonstrate compliance with the emission standards for NOx, CO, ammonia slip and visible emissions. NO_X emissions recorded by the CEM system shall be reported for each ammonia slip test run. Annual compliance with the applicable NOx and CO emissions standards can also be demonstrated with valid data collected by the required annual RATA at permitted capacity. {Permitting Note: Continuous compliance with the CO and NOx standards shall be demonstrated with certified CEMS system data.} [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

20. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. The CEM systems shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C.

   a. Compliance with the continuous CO emissions standards shall be based on a 3-hour block average starting at midnight of each operating day. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. If a unit operates less than 3 hours during the block, the 3-hour block average shall be the average of available valid hourly average emission rate values for the 3-hour block. The CO monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. For purposes of determining compliance with the CEM emission standards of this permit, missing or excluded data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour block average for CO. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding CO emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

b. The NO_X monitor shall have a span of no more than 10 ppmvd corrected to 15% oxygen. Compliance with the continuous NO_X emissions standards shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the CEM emission standards of this permit, missing (or excluded) data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding NO_X emissions standards specified in this section.
[Rule 62-212.400(BACT), F.A.C.]

21. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

OTHER REQUIREMENTS

The combined cycle gas turbine is also subject to the "Gas Turbine Common Conditions" specified in Section III.C as well as the "Standard Conditions" included as Appendix SC in Section IV.

This section of the permit addresses the following new emissions units.

Emissions Units 002 and 003: Simple Cycle Gas Turbine Nos. SC-1 and SC-2
Description:. Each simple cycle unit consists of a General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, and an evaporative inlet air-cooling system.
Fuel: Each simple cycle unit is fired exclusively with pipeline-quality natural gas.
Capacity: At a compressor inlet air temperature of 35° F and firing approximately 1700 MMBtu (LHV) per hour of natural gas, each unit produces approximately 180 MW.
Controls: Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of pipeline-quality natural gas at high temperatures. NO_X emissions are reduced by Dry Low-NO_X (DLN) combustion technology.
Stack Parameters: When operating at 100% load and at an inlet temperature of 35° F, exhaust gases exit a 135 feet tall stack that is 19.0 feet in diameter with a flow rate of approximately 2,500,000 acfm at 1092° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions standards specified for these emissions units represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

EQUIPMENT

2. Simple Cycle Gas Turbines: The permittee is authorized to install, tune, maintain and operate two new General Electric Model PG7241(FA) gas turbine-electrical generator sets. Each simple cycle unit shall be designed and operated to generate a nominal 175 MW of shaft-driven electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, a compressor inlet air evaporative cooling system, a single exhaust stack that is 135 feet tall and 19.0 feet in diameter, and associated support equipment. [Applicant Request; Design]

3. DLN Combustion Technology: The permittee shall tune, maintain and operate the General Electric DLN 2.6 combustion system to control NO_X emissions from each simple cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce NO_X emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
[Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Simple Cycle Operation Only: Each gas turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NO_X BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NO_X BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to restricted operation. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NO_X BACT analysis (as if never constructed) and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. The results of this analysis

may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards.
[Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

5. Permitted Capacity: The maximum heat input rate to each simple cycle gas turbine shall not exceed 1743 MMBtu per hour based on a compressor inlet air temperature of 35° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
[Design; Rule 62-210.200(PTE), F.A.C.]

6. Fuel Specifications: Each simple cycle gas turbine shall fire only pipeline-quality natural gas with a maximum of 1.5 grains of sulfur per 100 standard cubic feet of natural gas.
[Applicant Request; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

7. Restricted Operation: The two combustion turbines shall operate no more than an average of 5,000 hours per installed unit during any consecutive 12-month period. Each simple cycle gas turbine shall fire no more than 8,500,000 MMBtu of natural gas (LHV) during any consecutive 12-month period. {Permitting Note: This is approximately equivalent to 5000 hours of operation at 100% load.}
[Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to each simple cycle gas turbine. Unless otherwise noted, the mass emission limits are based a compressor inlet temperature of 35° F and 100% load. For comparison to the standard, actual measured concentration shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

8. Carbon Monoxide (CO): CO emissions from each simple cycle gas turbine shall not exceed 31.0 pounds per hour nor 8.0 ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]

9. Nitrogen Oxides (NO_X)

   a. *Initial Performance Test*: NO_X emissions from each simple cycle gas turbine shall not exceed 61.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load as determined by EPA Method 7E.

   b. *CEM System*: NO_X emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average as determined by valid data collected from the certified NO_X CEM system.

   NO_X emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

10. Particulate Matter (PM/PM_{10}): The fuel specifications established in Condition No. 6 of this section combined with the efficient combustion design and operation of the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Particulate matter emissions are expected to be less than 9 pounds per hour as determined by EPA Method 5, front-half catch only. [Rule 62-212.400(BACT), F.A.C.]

11. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2): The fuel sulfur specification established in Condition No. 6 of this section effectively limits the potential emissions of SAM and SO_2 from each simple cycle gas turbine. Compliance with the fuel sulfur specification shall be demonstrated by the sampling, analysis, record keeping and reporting requirements established in Section III.C of this permit.
[Rule 62-212.400(BACT), F.A.C.]

12. Volatile Organic Compounds (VOC)

    a. *Initial Performance Test*: VOC emissions from each simple cycle gas turbine shall not exceed 3.0 pounds per hour nor 1.3 ppmvd corrected to 15% oxygen based on a 3-hour test average at base load as determined by EPA Method 25A, measured and reported in terms of methane. Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
    [Rule 62-4.070, F.A.C.; To Avoid Rule 62-212.400(BACT), F.A.C.]

    b. *After Initial Performance Test*: The efficient combustion of a clean fuel and good operating practices minimize VOC emissions from each simple cycle gas turbine. Compliance with the fuel specifications and CO standards of this section shall serve as indicators of good combustion. Subsequent VOC emissions performance tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C.
    [Rule 62-4.070, F.A.C.]

EXCESS EMISSIONS

13. Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of each simple cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

    a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.

    b. *Work Practice BACT*: The unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

    c. *Low-Load Restriction*: Except for startup and shutdown, operation below 50 percent is prohibited.

    d. *CEM System NO_X Data Exclusion*: No more than two hourly average emission rate values shall be excluded from the continuous NO_X compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than a total of two hourly average emission rate values shall be excluded from the continuous NO_X compliance demonstrations for such periods in any calendar day. A "documented unavoidable malfunction" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

    [Design; Rules 62-210.700, 62-4.130, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{Permitting Note: Performance test methods are specified in Gas Turbine Common Conditions, Section III.C.}

14. Initial Tests Required: Each simple cycle gas turbine shall be tested initially and upon permit renewal to demonstrate compliance with the emission standards for PM/PM_{10}, CO, NO_X, VOC and visible emissions. The initial tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each unit. With appropriate flow measurements, certified CEM system data may be used to demonstrate compliance with the NOx standards. Tests for CO and VOC emissions shall be conducted concurrently. [Rule 62-297.310(7)(a)1., F.A.C.]

15. Annual Performance Tests: During each federal fiscal year (October 1st to September 30th), each simple cycle gas turbine shall be tested to demonstrate compliance with the emission standards for NOx, CO and visible emissions. Annual compliance with the applicable NOx and CO emissions standards can also be demonstrated with valid data collected by the required annual RATA at permitted capacity. NO_X emissions recorded by the CEM system shall be reported for each CO test run. {Permitting Note: Continuous compliance with the NO_X standard shall be demonstrated with certified CEMS system data.} [Rule 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

16. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record NO_X emissions from each simple cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. Each CEM system shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C. Each NO_X monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. Compliance with the continuous NO_X emissions standards shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the CEM emission standards of this permit, missing (or excluded) data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding NO_X emissions standards specified in this section.
[Rule 62-212.400(BACT), F.A.C.]

OTHER REQUIREMENTS

Each simple cycle gas turbine is also subject to the "Gas Turbine Common Conditions" specified in Section III.C as well as the "Standard Conditions" included as Appendix SC in Section IV.

C. GAS TURBINE COMMON CONDITIONS

This section of the permit addresses the following new emissions units.

ID	Emission Unit Description
001	**Combined Cycle Unit No. CC-1** consists of a natural gas fired General Electric Model PG7241FA 175 MW gas turbine-electrical generator set, an unfired heat recovery steam generator, and a separate turbine-electrical generator.
002	**Simple Cycle Unit No. SC-1** consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.
003	**Simple Cycle Unit No. SC-2** consists of a natural gas fired General Electric Model PG7241FA gas turbine-electrical generator set with a nominal capacity of 175 MW.

NEW SOURCE PERFORMANCE STANDARDS, SUBPART GG

1. NSPS Requirements: The Department determines that compliance with the emissions performance and monitoring requirements of Sections III.A and B also demonstrates compliance with the New Source Performance Standards for gas turbines in 40 CFR 60, Subpart GG. For completeness, the applicable Subpart GG requirements are included in Appendix GG of this permit. [Rule 62-4.070(3), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combined cycle gas turbine and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

3. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such emissions shall be included in any compliance demonstration based on continuous monitoring data. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

4. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
5, 5B, or 17	Determination of Particulate Matter Emissions from Stationary Sources {Note: For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

Test Methods, Continued

Method	Description of Method and Comments
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the Department.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

CONTINUOUS MONITORING REQUIREMENTS

5. CEM Systems: Each continuous emissions monitoring (CEM) system shall comply with the following requirements:

   a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semi-annually to each Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps.

   b. *NO_X Monitors.* Each NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60.

   c. *O_2 or CO_2 Monitors.* The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and/or NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel fired. Each O_2 and CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported quarterly to each Compliance Authority. The RATA tests required for the O_2 or CO_2 monitors shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *Data Collection.* Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. The CEM system shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen. The CEM system shall be used to demonstrate compliance with the CEM emission standards for CO and NO_X as specified in this permit. Upon request by the Department, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *Data Exclusion.* All required emissions data shall be recorded by the CEM systems during episodes of startup, shutdown and malfunction. CO and NO_X emissions data recorded during such episodes may be excluded from the corresponding compliance-averaging period subject to the conditions specified in Sections III.A and B of this permit. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Data Exclusion Reports.* A summary report of the duration of data excluded from each compliance average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined to include the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall include the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than quarterly, including periods in which no data is excluded or no instances of missing data occur.

g. *Notification*: If a CEM system reports CO or NO_X emissions in excess of an emissions standard, the permittee shall notify each Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

h. *Availability.* Monitor availability for CO and NO_X CEM systems shall be 95% or greater in any calendar quarter. The report required in Appendix XS of this permit shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS

6. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM reference methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

7. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of fuel consumption for each gas turbine in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

8. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption (million cubic feet of natural gas per month), heat input rates (million BTU per month), and hours of operation for each gas turbine for the previous month. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

REPORTS

9. Semi-Annually Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, emissions shall be reported as "excess emissions" when emission levels exceed the standards specified in this permit (including periods of startup, shutdown and malfunction). Within 30 days following the end of the six month period, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions, periods of data exclusion, and CEMS systems monitor availability for the previous six month period.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

D. OTHER EMISSIONS UNITS

This permit authorizes installation of the following emissions units.

ID	Emission Unit Description
004	**Cooling Tower** : One 5-cell mechanical draft fresh water cooling tower.
005	**Other Emissions Units:** One 2600 hp diesel generator, one 250 hp diesel fire pump, aqueous ammonia storage tank, a 12.8 MMBtu/hr (HHV) gas-fired fuel heater and two diesel fuel storage tanks (each less than 1000 gallons).

1. Cooling Tower: BACT for the Cooling Tower was determined to be the use of fresh water and drift eliminators designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. A not to exceed limit of 4200 mg/l total dissolved solids shall be maintained within the cooling tower. {Permitting Note: Potential emissions in tons per year are expected to be less than 1.64 for PM and 0.99 for PM_{10}}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].
2. 2600 HP Diesel Generator: The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.12 for PM, 3.26 for NOx, 0.73 for CO, 0.07 for SO_2 and 0.18 for TOC (total organic carbons)}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].
3. 12.8 MMBtu/hr Gas-fired Natural Gas Fuel Heater: This unit is subject to applicable provisions of 40 CFR 60, Subpart Dc. New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].
4. 250 HP Diesel Fire Pump: The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.013 for PM, 0.74 for NO_X, 0.18 for CO, 0.0014 for SO_2 and 0.08 for TOC (total organic carbons)}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].
5. Aqueous Ammonia Storage Tank: This unit will contain less than a 20 percent concentration of aqueous ammonia by volume and therefore is not subject to applicable provisions of 40 CFR 68, Chemical Accident Provisions. [Rule 62-4.070 (3) F.A.C.]
6. Two Diesel Fuel Storage Tanks (each less than 1000 gallons): This unit shall store 0.05% or less sulfur diesel fuel (by weight). [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

El Paso Manatee Energy Center
PSD-FL-318 and 0810199-001-AC
Manatee County, Florida

BACKGROUND

The applicant, El Paso Merchant Energy Company (El Paso), proposes to install three nominal 175-megawatt (MW) General Electric PG 7241FA (GE 7FA) combustion turbine-electrical generators at the planned Manatee Energy Center near Piney Point, Manatee County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.b., Florida Administrative Code (F.A.C.). It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

Two of the units will operate in simple cycle mode and intermittent duty while the third will operate in combined cycle mode and continuous duty. The units will exhaust through separate 135-foot stacks. The units will be fired exclusively with pipeline natural gas. El Paso proposes to operate the simple cycle units up to 5,000 hours per year per unit. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination, accompanying the Department's Intent to Issue dated September 11, 2001.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on March 28, 2001 (complete June 27) and included a BACT proposal prepared by the applicant's consultant, ECT.

PREPARED BY:

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

ORIGINAL BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Selective Catalytic Reduction	9 ppmvd @ 15% O_2 (simple cycle units) 3.5 ppmvd @ 15% O_2 (combined cycle)
Particulate Matter	Pipeline Natural Gas Combustion Controls	18.3 pounds per hour (Front + Back Half, Simple) 20 pounds per hour (Front + Back Half, Combined)
Carbon Monoxide	As Above	7.4 ppmvd (Full load, Simple or Combined) 12 ppmvd (Combined Cycle Steam Augmentation)
Sulfur Oxides	As Above	1.5 grains sulfur/100 std cubic feet

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

The EPA currently stresses that BACT should be determined using the "Top-Down" approach, particularly when permits are issued by states acting on behalf of EPA. The Department considers Top-Down to be a useful tool, though not a unique or required approach to achieve a BACT under the State regulations. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by El Paso is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the El Paso project.

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

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple and combined cycle turbines. The proposed El Paso project is included to facilitate comparison.

TABLE 1

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" SIMPLE CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
El Paso Manatee, FL	350	9 NG	DLN	2x175 MW GE 7FA CTs (Gas only
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Draft 8/2001. Gas Only
Enron Deerfield, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 500 hrs on oil
Enron Pompano, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Revised Draft 06/01. 500 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE 7FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

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

TABLE 2

RECENT CO, VOC, AND PM EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" SIMPLE CYCLE PROJECTS

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
El Paso Manatee, FL	8 (7.4@15% O_2) - N	1.4 (1.3@15% O_2)	18 lb/hr (Front & Back	Clean Fuels Good Combustion
El Paso Deerfield, FL	8 (7.4@15% O_2) - NG	1.4 (1.3@15% O2)	18 lb/hr (Front & Back)	Clean Fuels Good Combustion
Enron Deerfield, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

TABLE 3

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Capacity Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
El Paso Manatee, FL	250	2.5 – NG	SCR	175 MW GE 7FA
El Paso Deerfield, FL	250	2.5 – NG	SCR	175 MW GE 7FA Draft 8/2001
CPV Pierce, FL	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT 7/2001
Metcalf Energy, CA	600	2.5 – NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce, FL	~250	3.5 – NG 10 - FO	SCR	170 MW MHI501F CT Repowering
CPV Atlantic, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
CPV Gulfcoast, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT
TECO Bayside, FL	1750	3.5 – NG 12 - FO	SCR	7x170 MW GE 7FA CTs Repowering
FPC Hines II, FL	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F
Calpine Osprey, FL	527	3.5 – NG	SCR	2x170 MW WH501F Draft 5/00
Calpine Blue Heron, FL	1080	3.5 – NG	SCR	4x170 MW WH501F Draft 2/00
Santee Cooper, SC	~500	9 – NG	DLN	2x170 MW GE 7FA CTs ~ 4/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG (12 – simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
Lake Worth LLC, FL	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
CT = Combustion Turbine

TABLE 4

RECENT CO, VOC, AND PM EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppmv (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
El Paso Manatee, FL	9 (7.4 @15% O_2) 15 (12 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Deerfield, FL	9 (7.4 @15% O2) 15 (12 @15% O2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Pierce, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Metcalf Energy, CA	6 - NG (100% load)	.00126 lb/mmBtu-NG	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Enron Ft. Pierce, FL	3.5 - NG 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity	Oxidation Catalyst Clean Fuels Good Combustion
CPV Atlantic, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Gulfcoast, FL	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	9 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)	1.3 – NG 3 - FO	12 lb/hr – NG 30 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	16 - NG (24-hr CEMS) 30 – FO (24-hr CEMS)	2 – NG 10 – FO	10% Opacity – NG 5/9 ammonia – NG/FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Calpine Blue Heron, FL	10 – NG (24-hr CEMS) 17 – NG (DB&PA)	1.2 – NG 6.6 – NG (DB&PA)	31.9 lb/hr – NG (DB&PA) 10 percent Opacity 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Alabama Power Theo	~36 – CT & DB	~12.5 CT & DB		Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion

All of the projects listed above control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. In every case, pipeline quality natural gas is used and has a sulfur content less than 2 grains per 100 cubic feet. In some cases, the limits are even lower or are expressed in different terms. However all ultimately rely on a fairly uniform gas distribution network and have very little flexibility in actually controlling sulfur content. Similarly, emissions of these two pollutants are controlled by using 0.05 percent sulfur distillate fuel oil.

Some of the projects listed above include front and back half catch for PM limits. Therefore comparison is not simple.

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

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

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

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as the El Paso Manatee Energy Center.

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

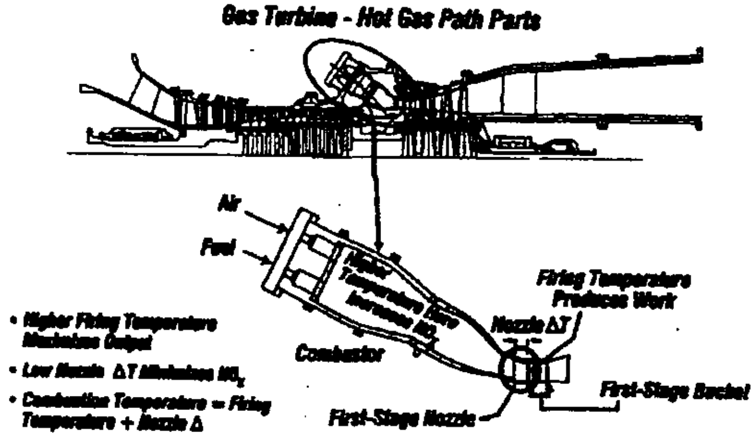

Figure 1 – Relation Between Flame Temperature and Firing Temperature

NO_X Control Techniques

Wet Injection

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

Combustion Controls: Dry Low NO_X (DLN)

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2.

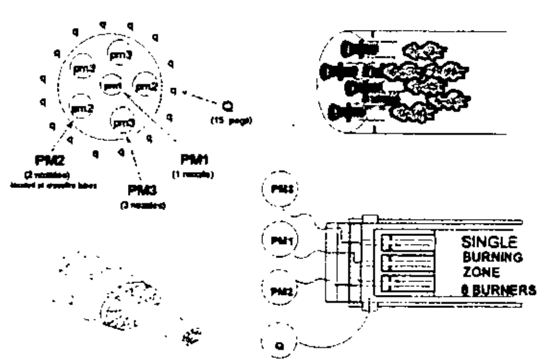

Figure 2 – DLN-2.6 Fuel Nozzle Arrangement

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

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

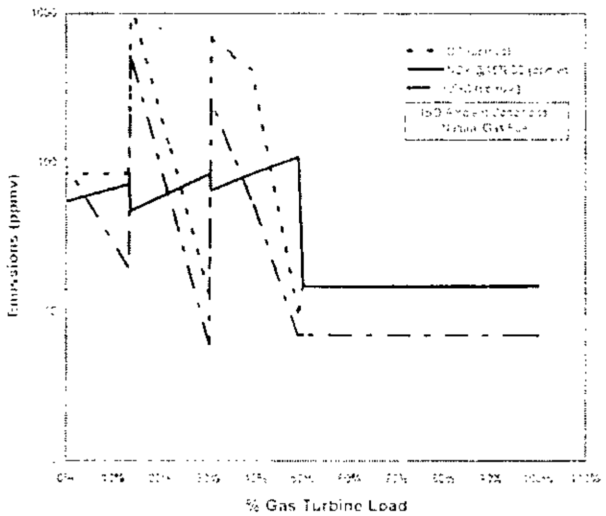

Figure 3 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

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

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[1] The DLN-2.6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd. The results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	
80	6.1	
90	6.6	
100	8.7	0.85
Limit	12	25

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[2] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd. Again, the results are all superior to the emission characteristics given in Figure 3.

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

Recent conversations with other operators indicate that the "Dry Low NO_X" characteristics extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE.[3]

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 4 from an EPRI report.[4] Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 4.

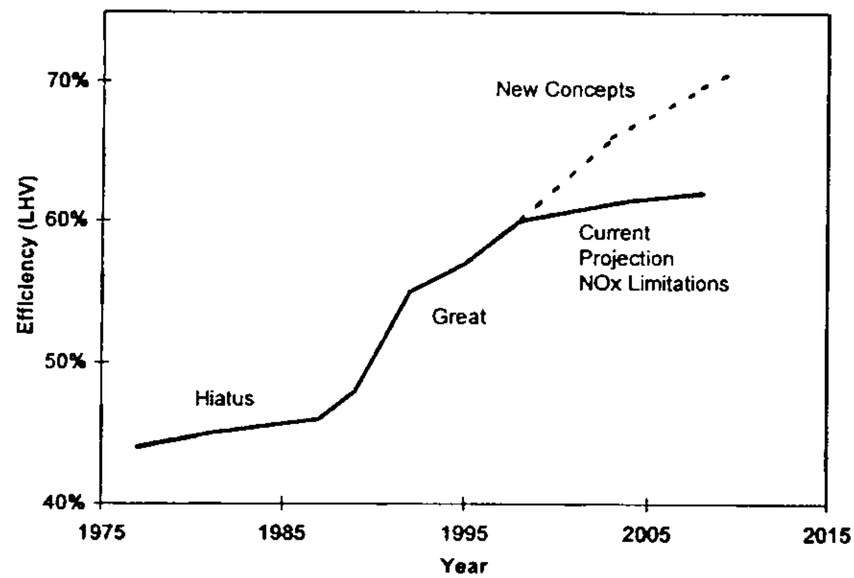

Figure 4 – Efficiency Increases in Combustion Turbines

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

Catalytic Combustion: XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[5] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

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

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[6] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma that documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

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

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

Selective Catalytic Combustion: SCR

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

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

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

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued recently to Competitive Power Ventures (CPV), Calpine, Florida Power Corporation, and Tampa Electric to achieve 3.5 ppmvd. More recently a permit was issued to CPV for its Pierce, Polk County project with a limit of 2.5 ppmvd @15% O_2 by SCR.

Figure 5 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 6 is a photograph of FPC Hines Energy Complex. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

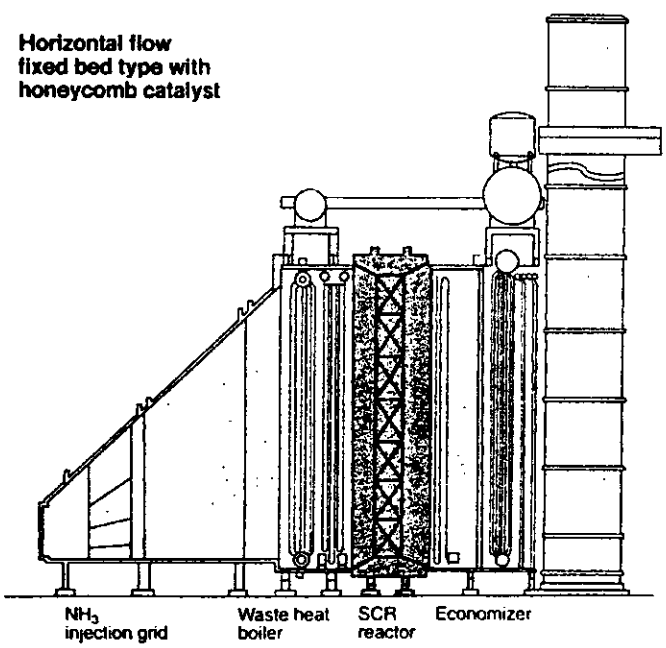

Figure 5 – SCR System within HRSG

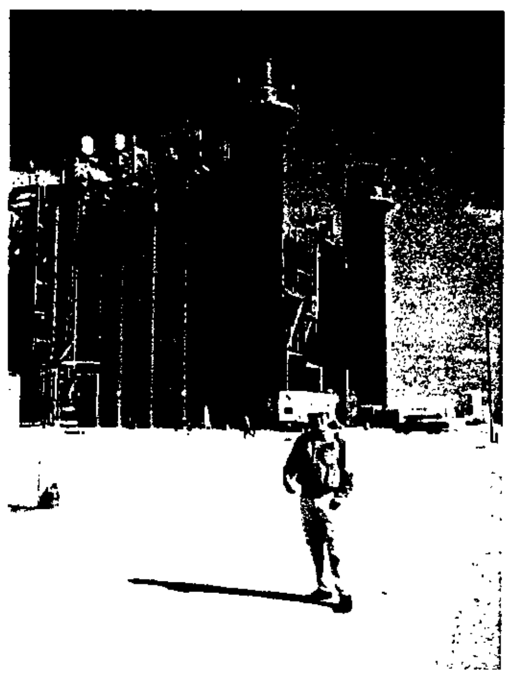

Figure 6 – FPC Hines Power Block I

Selective Non-Catalytic Combustion

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

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

$SCONO_X$™

$SCONO_X$™ is a catalytic add-on technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[8]

California regulators and industry sources stated that the first 250 MW block to install $SCONO_X$™ will be at PG&E's La Paloma Plant near Bakersfield.[9] The overall project includes several more 250 MW blocks with SCR for control.[10] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine equipped with $SCONO_X$™.

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

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [11] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmvd. More recently, Goal Line announced that $SCONO_X$™ has in practice achieved emissions of 1.3 ppmvd.[12]

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[13]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for the simple cycle units proposed in this application.

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

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

For this project, the applicant has proposed as BACT the use of pipeline natural gas. The applicant estimated total emissions for the project at 69 TPY of SO_2 and 10 TPY of SAM. The Department expects the emissions to be lower because the typical natural gas in Florida contains less than the 1.5 grains of sulfur per 100 standard cubic feet (gr S/100scf) specification proposed by El Paso. This value is well below the "default" maximum value of 20 gr S/100 scf characteristic of natural gas, but is still high enough to require a BACT determination.

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

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

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

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 181 tons per year (including filterable and condensable particulate fractions).

Drift eliminators will be installed on the freshwater mechanical draft cooling tower to reduce PM/PM_{10}. The drift eliminators proposed by El Paso will reduce drift to 0.0005 percent of the circulating water flow rate. This is equivalent to approximately 1 and 1.6 tons per year of PM_{10}.and PM respectively.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

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

CO is emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO. There is a great deal of uncertainty regarding actual CO emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions have actually been reported from several facilities without use of oxidation catalyst. For example, although Westinghouse does not offer a single digit CO guarantee on the 501F, the units installed at the FPC Hines Energy Complex achieved CO emissions in the range of 1-3 ppmvd on both gas and fuel oil at full load.[14] As previously discussed, GE 7FA units achieved similar results when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent.

CO emissions *should* be low (at least at full load) because of the very high combustion temperatures characteristic of "F-Class" turbines. It appears that contract writing has not yet "caught up" with the field experience to consistently guarantee low CO emissions for F-Class units, at least at high loads.

One alternative is to complete the combustion by installation of an oxidation catalyst. Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd.

A recent permit was issued by the Bay Area AQMD in California for the Metcalf Energy Center. The limit for CO from a Siemens-Westinghouse 501F gas turbine is 6 ppmvd (at full load). No Catalyst is required. However it is doubtful that performance can be maintained at low load.

A recent draft permit was issued by the Department that limits CO to 3.5 ppmvd on a Mitsubishi 501F combustion turbine.[15] Enron will install an oxidation catalyst at Ft. Pierce in order to avoid high CO emissions at low load (<70 percent of full load). This results in the ability to obtain a guarantee for the low permitted level at full load. This would not have been a concern if the units were GE7FAs for the reasons discussed above.

The limit originally proposed by El Paso for the Manatee Energy Center under normal operation is 7.4 ppmvd @15% O_2 at full load. This is consistent with the description of the DLN-2.6 technology. The expected results are 1-2 ppmvd and are actually better than what the Enron and Metcalf projects will likely achieve across the 50-100 percent operating range.

A higher limit of 12 ppmvd @15% O_2 was originally proposed during power augmentation for the combined cycle unit. Under this mode, steam from the HRSG is re-injected into the combustors to boost power production. One consequence is that CO emissions can increase.

Since the original review, El Paso proposed oxidation catalyst to allow continuous power augmentation and to minimize startup emissions. Total annual emissions of CO for the project are now expected to be little more than 100 tons per year based on the new proposed limits of 2.5 ppmvd under normal modes and 4 ppmvd during power augmentation. Actual emissions will probably be much lower.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limit proposed by El Paso for this project is 1.1 ppmvd @ 15% O_2 for all modes of operation. According to GE (and Department data), VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[16]

Based on the chosen equipment, the Department believes that annual VOC emissions will be less than 40 TPY. Therefore a BACT determination is not required.

BACKGROUND ON PROPOSED GAS TURBINE

El Paso plans to install three nominal 175-MW General Electric 7FA gas turbines, one of which will operate in combined cycle mode. Per the discussion above, such units are capable of achieving and have achieved (with DLN and SCR technology) all of the emission limits proposed by El Paso as BACT.

The GE Speedtronic™ Mark VI Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include fuel control in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark VI also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[17]

STARTUP AND SHUTDOWN EMISSIONS

The Department defines "Startup" as follows[18]:

"Startup" - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

The Department permits excess emissions during startup and shut down as follows:[19]

Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

The Department defines "Excess Emissions" as follows:[20]

"Excess Emissions" - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, sootblowing, load changing or malfunction.

The U.S. EPA Region IV office recently recommended that the Department consider "establishment of startup and shutdown BACT for CO and NO_X such as mass emission limits (e.g., pounds of emissions in any 24-hour period) that include startup and shutdown emissions, or future emission limits derived from monitoring results during the first few months of commercial operation."[21]

The Department reviewed a number of emission estimates and permit conditions addressing startup and shutdowns for projects in California, Georgia, Washington, and Mississippi and has determined that much of the information is based on estimates that are very difficult to verify.

A review of published General Electric information indicates that features are incorporated into the design of the DLN-2.6 technology specifically aimed at minimizing emissions. One of the key elements was to incorporate lean pre-mixed burning while operating the unit in low load and startup.[22] This is in contrast with the previous DLN-2.0 technology that relied on diffusion mode combustion at four of the burners in each combustor during startup and low load operation.

During startup of a GE 7FA simple cycle unit, NO_X concentrations in the exhaust are greater than during full-load operation. The concentrations are estimated at 20 to 80 ppmvd @15% O_2 during the first 10 minutes or so after the unit is actually firing fuel. This occurs while only one to four of the six nozzles shown in Figure 2 are in operation on each combustor.

Within the following 5 minutes, the unit switches to Mode 5 (or 5 Q), during which NO_X concentrations are typically less than 10 ppmvd even though the unit is not yet at full load.[23] The Low-NO_X modes occurs when at least the five outer nozzles are in operation.

Given the short duration and the relatively low exhaust rate (and load) during the high pollutant concentration phases of simple cycle startup, the Department believes that the NO_X emissions during the first hour of startup and operation will be approximately equal to emissions during an hour of full load steady-state operation. Arguments covering shutdown are similar and the time is more compressed so that the Department believes the conclusion is the same for startup as for shutdown.

NO_X concentrations in the exhaust during startup and shutdown will be less than the New Source Performance Standard limit of approximately 110 ppmvd @15% O_2 applicable to F-Class turbines. A simple cycle unit will typically have one startup and shutdown every day that it is used.

The startup scenarios for a GE 7FA combined cycle unit are as follows:

Hot Start:	One hour following a shutdown less than or equal to 8 hours.
Warm Start:	Two hours following a shutdown between 8 and 48 hours.
Cold Start:	Four hours following a shutdown greater than or equal to 48 hours.

During a combined cycle cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated up. During a portion of the 4 hour startup, emissions will be roughly 60 to 80 ppmvd NO_X @15% O_2. Once the HRSG is heated sufficiently, the ammonia system is turned on to abate emissions.

While NO_X emissions during the initial phase of startup (low load and no ammonia injection) are greater than during full load steady state operation, such startups are infrequent. Also, it is noted that such a cold startup would be preceded by a shutdown of at least 48 hours. Therefore the startup emissions would not cause annual emissions greater than the potential-to-emit under continuous operation. Similar analyses can be performed for warm startups and hot startups.

The combined cycle startup scenario described above can (at least in theory) be modified by use of a bypass stack and damper.[24] Under this scenario, the steam cycle can be slowly brought up to load while the gas turbine reaches full load as fast as it would under simple cycle mode. The exhaust gas can be modulated in such a fashion that the HRSG and steam turbine are ramped up slowly in accordance with their respective specifications. At the same time, the gas turbine will quickly accelerate to the DLN modes (5Q or 6Q) thus minimizing emissions. In this manner the startup NO_X and CO concentrations are reduced to the values observed during simple cycle startup. Thereafter the unit will exhibit the same characteristics (for about three hours) as a simple cycle unit in steady-state operation until the ammonia system is actuated.

Implementation of bypass modulation requires an additional stack and design features to minimize stratification and uneven heating of boiler tube bundles in the HRSG. The initial response from GE is that such a configuration at a project in Hungary resulted in equipment damage and leakage of exhaust gas to the atmosphere resulting in a significant loss in performance.[25]

The Department is gathering information from recently commissioned 7FA units to more accurately estimate startup emissions for NO_X and address carbon monoxide too.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the El Paso project assuming full load. Values for NO_X and CO are corrected to 15% O_2 on a dry volume basis. These emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are specified in the permit.

POLLUTANT	CONTROL TECHNOLOGY	DEPARTMENT'S PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Selective Catalytic Reduction	9 ppmvd @ 15% O_2 (simple cycle units) 2.5 ppmvd @ 15% O_2 (combined cycle) 5 ppm ammonia slip from combined cycle unit
Particulate Matter	Pipeline Natural Gas Combustion Controls	20 pounds per hour (filterable plus condensable) 0.0005 % drift of circulating rate – cooling tower
Visible Emissions	As Above	10 Percent (surrogate for PM_{10})
Carbon Monoxide	As Above	7.4 ppmvd @15% O_2 (full load, simple or combined) 12 ppmvd@15% O_2 (limited power augmentation)
Sulfur Oxides	As Above	1.5 grain sulfur/100 std cubic feet
All (Ancillaries)	Low Sulfur Fuels Drift Eliminators on Cooling Tower	1.5 grain sulfur/100 std cubic feet 0.05% sulfur (oil) 0.0005 percent drift

RATIONALE FOR DEPARTMENT'S DETERMINATION

- Certain control options are feasible on combined cycle units but not on simple cycle units. This rules out Low Temperature (conventional) SCR, and $SCONO_X$ on simple cycle units. XONON is claimed to be available for F Class gas-fired projects.
- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are high temperature (Hot) SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.

- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- The levelized costs of NO_X removal by Hot SCR for the El Paso project were estimated by El Paso at $22,052 per ton assuming 5,000 hours of operation. The estimates are based on reducing NO_X emissions from 9 to 3.5 ppmvd @15% O_2.
- The Department does not accept the precise Hot SCR cost calculations presented by El Paso and considers them on the high end. But even at half the cost estimated by El Paso, the Department would agree that Hot SCR is not cost-effective for this project.
- XONON is rejected because it has not yet been demonstrated in large combustion turbines and is likely to be even less cost-effective than Hot SCR.
- The Department accepts El Paso's BACT proposal of 9 ppmvd NO_X @15% O_2 for the simple cycle units <u>and</u> exclusive use of natural gas. The Department notes that data from the City of Tallahassee and TECO demonstrate that the GE 7FA units actually achieve 6 to 8 ppmvd @15% O_2.
- The proposed BACT limit of 9 ppmvd for the simple cycle units is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The Department's overall BACT determination for the simple cycle units is equivalent to approximately 0.35 lb of NO_X per megawatt-hour (lb/MWH) by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a (fuel independent) limit of 1.6 lb/MW-hr.
- The Department will limit operation of the two units to an average of 5,000 hours per year per simple cycle unit. The Department will further limit the operation of each and every individual unit to the fuel-equivalent of 5,000 full load hours of operation. The purpose is to maintain the conclusion regarding cost-effectiveness under intermittent duty operation.
- Although startup and shutdown emissions are generally exempt, emissions during startup and shutdown are less than the NSPS limit of 110 ppmvd @15% O_2 (that applies during steady-state operation).
- The Department does not yet have sufficient information from field experience to set start-up and shutdown emissions limits. However, the modes that give rise to high NO_X concentration have been identified. The Department will therefore set a work practices standard as BACT.
- The Work Practice BACT for simple cycle startup is that the unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. The shutdown case is trivial.
- The Lowest Achievable Emission Rate (LAER) for a combined cycle unit is approximately 2 ppmvd NO_X at 15 percent oxygen (@15% O_2) while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line, has requested recognition of a 1.3 ppmvd NO_X value as *achieved in practice*.
- There are several projects for large turbines in Massachusetts, Connecticut, New York, and California requiring SCR with a NO_X emission limit of 2 ppmvd @15% O_2.

- The "Top" technology in a top/down analysis for a combined cycle unit will achieve approximately 2 ppmvd @15% O_2 by either $SCONO_X$ or SCR.
- El Paso estimated the cost effectiveness of $SCONO_X$ at $24,187 per ton of NO_X removed. The Department does not necessarily accept the precise $SCONO_X$ cost calculations presented by El Paso. However, even at half the cost estimated by El Paso, the Department agrees that $SCONO_X$ would not be cost-effective for this project.
- El Paso estimated the cost-effectiveness of conventional (cold temperature) SCR at $3,535 per ton of NO_X while reducing emissions from 9 to 3.5 ppmvd @15% O_2. The Department accepts El Paso's estimate and believes this cost-effectiveness can be maintained while achieving an NO_X emission rate of 2.5 ppmvd @15% O_2.
- The National Park Service advised in its review of the application that BACT determinations of 2.5 ppmvd NO_X @15% O_2 have recently been issued for combined cycle projects in Maine and Washington. The Park Service also agreed that 9 ppmvd represents BACT for simple cycle units.[26]
- The Department concludes that 2.5 ppmvd NO_X @15% O_2 (with 5 ppmvd ammonia slip) while firing natural gas in a combined cycle unit constitutes BACT. This value for the conventional SCR option takes into consideration the measurement uncertainties at low emission rates and minimizes particulate emissions due to ammonia emissions.
- EPA advised that the proposed 2.5 ppmvd limit is equal to the lowest value established in Region IV, that the 24-hour averaging time is acceptable in light of the low limit, and that the ammonia limit is consistent with projects outside the Region (notwithstanding lack of rule authority or a policy within EPA).
- The effects of aqueous ammonia use and ammonia slip are not unacceptable. In fact, ammonia is used throughout the nearby fertilizer complexes in Hillsborough, Polk, and Manatee County.
- The Department's overall BACT determination for the combined cycle unit is less than 0.07 lb of NO_X per megawatt-hour (lb/MWH) by Dry Low NO_X.
- The Work Practice BACT for combined cycle startup is that the combustion turbine will start up and operate as a simple cycle unit and modulate exhaust to the HRSG. This requires installation of a bypass stack and damper. The unit shall reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. Ammonia injection will be practiced within three hours after gas turbine ignition and crossfire.
- The Department does not have a cost estimate for the additional stack and design requirements, but believes the additional power and flexibility offered by full load simple cycle operation during the cold startup of the steam cycle more than compensates for the additional costs.
- In lieu of the Department's determination regarding Work Practice BACT, the company will install dampers (but no bypass stack) to retain as much heat as possible during periods of shutdown. This will tend to reduce the number of long cold startups in comparison with the shorter hot startups.
- The applicant estimates VOC emissions of 1.1 ppmvd @15% O_2 (or less) for all firing modes. These levels will not trigger PSD or a requirement for a BACT determination.

- El Paso estimated levelized costs at $9,000 per ton to reduce emissions at the simple cycle units from about 7.4 to 0.7 ppmvd CO @15% O_2. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- In view of the performance of GE 7FA units without add-on control (~ 0 - 4 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective for the simple cycle units based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- El Paso estimated levelized costs for CO catalyst control at $2,475 to reduce emissions from 11.7 to 1.2 ppmvd @15% O_2 for the combined cycle unit operating in power augmentation mode.
- In view of the performance of GE 7FA units cited in the discussion above (Tallahassee and TECO Polk Power data) without add-on control (~ 1 ppmvd), it appears to the Department that oxidation catalyst costs are substantially biased to the low side based on *actual* emissions.
- The Department determines BACT for CO achievable by good combustion as 7.4 ppmvd @15% O_2 at full load and 8 ppmvd @15% O_2 over the full operational range for simple cycle and combined cycle operation. Additionally, the Department determines BACT for CO as 7.4 ppmvd @15% O_2 for the combined cycle unit during power augmentation if unlimited and 12 ppmvd @15% O_2 if limited to 2000 hours per year.
- The CO BACT determination of 8 ppmvd @15% O_2 under normal combined cycle operation and 12 ppmvd @15% O_2 under (limited) power augmentation are low and within the range of recent BACT determinations for combustion turbines in the Southeast.
- El Paso proposes to install CO catalyst to allow unlimited power augmentation. The catalyst will also reduce emissions of CO (and VOC and HAPs) during startup and under all modes of operation. El Paso proposes to reduce CO emission limits to 2.5 and 4.0 ppmvd @15% O_2 for normal and (unlimited) power augmentation conditions respectively.
- The Department acknowledges El Paso's request and will lower the emissions accordingly. This does not imply that the Department has determined that BACT for is 2.5 ppmvd for normal operation or that BACT is 4.0 ppmvd for (limited) power augmentation or that oxidation catalyst is necessarily required to meet the Department's BACT determination.
- BACT for sulfur oxides for this project (including the ancillary equipment emission units) is the exclusive use of pipeline natural gas with a specification of 1.5 grains per 100 standard cubic feet. Pipeline quality natural gas in Florida contains less than this value.
- The Department agrees that inlet air filtration, good combustion, and use of inherently clean fuels constitute BACT for PM/PM_{10} for this project (including ancillary equipment emission units).
- The emission limit for PM_{10} from the combustion turbines will be set at 11 pounds per hour. This value is based on filterable fraction only per the Department's definition of PM/PM_{10}. Expected particulate emissions based on filterable plus condensable particulate matter are 20 pounds per hour.
- The Department will set a visible emissions BACT limit at 10 percent. The Department will rely on VE observation as a surrogate for PM/PM_{10} BACT compliance (after the initial PM/PM_{10} test).

- BACT for the Cooling Tower was determined to be use of fresh water and drift eliminators designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. A lower drift rate would be reasonable for project where reused wastewater is the cooling medium.

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions (initial, annual)	Method 9
PM/PM_{10} (initial)	Method 5 (Front-half catch)
VOC	Method 25A corrected by methane from Method 18
CTM-027(initial, quarterly, annual)	Procedure for Collection and Analysis of Ammonia in Stationary Sources
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
CO (initial, annual, CEMS)	Method 10; CO-CEMS (continuous 3-hr block average)
NO_X (continuous 24-hr)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (initial and annual)	Annual Method 20 (can use RATA if at capacity); Method 7E

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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1/16/02
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1/16/02
Date

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SECTION IV. APPENDIX GC

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

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

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

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

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

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

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

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

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

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

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

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

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

NSPS SUBPART GG REQUIREMENTS

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

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

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

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

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

where:

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

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

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

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

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

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

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

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" value for this unit is approximately 10 for natural gas. The equivalent emission standard is 108 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

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

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

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

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

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

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

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

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

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

where:

NOx	=	emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H_2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

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

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

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

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

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

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

SECTION IV. APPENDIX SC
STANDARD CONDITIONS

{Permitting Note: The following conditions apply to all emissions units and activities at this facility.}

EMISSIONS AND CONTROLS

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

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

3. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. [Rule 62-210.700(4), F.A.C.]

4. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

5. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

6. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

7. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

[Rule 62-297.310(4), F.A.C.]

8. Determination of Process Variables

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to

CONTINUOUS MONITOR SYSTEMS SEMI-ANNUAL REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From ________________ to ________________

Company: ________________

Emission Limitation: ________________

Address: ________________

Monitor Manufacturer and Model No.: ________________

Date of Latest CMS Certification or Audit: ________________

Process Unit(s) Description: ________________

Total source operating time in reporting period [a]: ________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months.

I certify that the information contained in this report is true, accurate, and complete.

____

Name

____

Title

________________ ________________

Signature *Date*

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Al Linero ay for CHF

FROM: Teresa Heron TH

DATE: January 16, 2001

SUBJECT: El Paso Manatee Energy Center
600 Megawatt Gas-fueled Power Plant
DEP File No. 0810199-001-AC (PSD-FL-318)

Attached is the final package for construction of a 600 MW gas-fueled power plant near Piney Point in Manatee County. The plant will consist of a 250 MW combined cycle and two intermittent duty, simple cycle, 175 MW GE 7FA combustion turbines along with ancillary equipment. There is no fuel oil issue on this project.

The NO_X BACT limit for the combined cycle unit was determined to be 2.5 ppmvd @15% O_2 on a 24-hr average time and 5 ppmvd ammonia slip. We determined that BACT for CO is 7.4 ppmvd @15% O_2.and 12 ppmvd for limited power augmentation on the combined cycle unit.

Because El Paso wanted unlimited power augmentation (steam injection), they decided to install oxidation catalyst and requested modification of the limits to 2.5 and 4 ppmvd for normal operation and (unlimited) power augmentation, respectively. This is the first oxidation catalyst to be installed on a GE 7FA in this state. They plan to do the same at their Broward project as part of an effort to resolve the case there.

We would still consider our draft BACT determination to be applicable for a combined cycle project with limited power augmentation. We clarified the special conditions that brought about the more stringent standard and oxidation catalyst installation. Under normal operations (i.e. not power augmentation) such units actually achieve about 1 ppmvd without oxidation catalyst. Therefore except for combined cycle cold startups, and substantial power augmentation, there is little tangible benefit in oxidation catalyst on such units.

The simple cycle units will meet NO_X and CO limits of 9 and 7.4 ppmvd @15% O_2, respectively. There is no power augmentation issue on simple cycle and no CO catalyst is proposed. The units reach full load and low CO emissions modes very rapidly.

We recommend your approval of the attached permit and BACT determination.

AAL/th

Attachments