Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

October 29, 2004

Mr. Richard Craig, V.P. of Southeastern Operations
Florida Gas Transmission Company
P. O. Box 4657
Houston, TX 77101-4657

Re: Air Construction Permit No. 0950190-006-AC
Florida Gas Transmission Company, Compressor Station 18
Revision to Increase Heat Input for Engine 1806

Dear Mr. Craig:

On September 10, 2004, you submitted an application to revise the original air construction permit to increase the maximum heat input rate for Engine 1806. You have also requested revisions to include notification/testing requirements for "functionally equivalent" component replacements and to incorporate the amended Subpart GG fuel monitoring requirements. The affected units are installed at existing Compressor Station 18, which is located at 7990 Steer Lake Road in Orlando, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Permitting Authority's technical review of the application and provides the rationale for making the preliminary determination to issue a Draft Permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Draft Permit No. 0950190-006-AC
(Revision of Original Air Permit No. 0950190-004-AC)
Increased Heat Input Rate for Engine 1806

COUNTY

Orange County

APPLICANT

Florida Gas Transmission Company
Existing Compressor Station 18
ARMS Facility ID No. 0950190

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting South Program

October 19, 2004

{Filename: 0950190-006-AC - TEPD}

1. APPLICATION INFORMATION

Facility Description

The Florida Gas Transmission Company operates existing Compressor Station 18, which is located at 7990 Steer Lake Road in Orlando, Florida. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The Standard Industrial Classification for "Natural Gas Transmission: is SIC No. 4922. Compressor Station 18 consists of: three 2000 bhp engines that were installed in 1962; a 2000 bhp engine that was installed in 1968; a 2700 bhp engine that installed in 1991 (PSD); and a 7200 bhp gas turbine installed in 2003. The primary regulatory categories are:

Title III: The facility is a major source of hazardous air pollutants (HAP).

Title IV: The facility has no units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution (Chapter 213, F.A.C.).

PSD: The facility is a PSD-major source of air pollution (Rule 62-212.400, F.A.C.).

NSPS: The gas turbine is subject to the New Source Performance Standards in Subpart GG of 40 CFR 60.

Project Description

Engine 1806 was constructed under Air Permit No. 0950190-004-AC as a 7200 bhp gas turbine to be used as a natural gas pipeline compressor engine. The applicant requests the following changes to the original permit.

- Based on performance testing, the installed gas turbine fires more natural gas to produce the required power output. The applicant requests that the permitted maximum heat input rate be increased form 63 to 68 MMBtu per hour.
- In July of 2004, EPA amended the federal fuel monitoring requirements in Subpart GG of 40 CFR for gas turbines. The applicant requests a permit revision to be consistent with the amended fuel monitoring requirements.
- Engine 1806 is a light-industrial gas turbine with a power output of approximately 7200 bhp. It is common practice within the gas pipeline industry to replace the gas generator for maintenance and repair with a functionally equivalent component. The replaced gas generator is then shipped to a regional facility for maintenance and placed back into a pool of similar components. The applicant requests specific notification and testing requirements for conducting such functionally equivalent component replacements.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-296	Emission Limiting Standards
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the following sections of the Code of Federal Regulations (CFR).

Title 40, CFR	Description
Part 60	Subpart A - General Provisions for NSPS Sources
	NSPS Subpart GG - Stationary Gas Turbines
	Applicable Appendices

3. INCREASE HEAT INPUT FOR ENGINE 1806

Engine 1806 is a Cooper-Rolls Royce Model KC7-DLE gas turbine nominally rated at 7200 bhp (ISO). The conditions for an "ISO" standard day are 59° F, 60% relative humidity, and 14.7 psi pressure. The unit is permitted for a capacity of 63 MMBtu per hour at a compressor inlet temperature of 59° F when producing approximately 7200 bhp of output. As installed, the performance curves indicate a maximum heat input rate of about 68 MMBtu per hour at a compressor inlet temperature of 59° F when producing approximately 6600 bhp. Apparently, the unit is not as efficient as initially believed. However, the initial compliance test results also show that the gas turbine is well below the permitted emission rates.

Increasing the maximum heat input rate from 63 to 68 MMBtu per hour simply recognizes the capabilities of the installed unit. FGTC continues to work with Rolls Royce to improve the performance. The permit standards will not change as a result of this revision. Only "equivalent maximum emissions" will increase slightly because these rates were directly based on the maximum heat input rate. The minimal change in heat input will not result in significant actual emissions increases. The Department will approve this request.

4. REVISED FUEL MONITORING REQUIREMENTS

In July of 2004, EPA amended the fuel monitoring requirements for gas turbines subject to NSPS Subpart GG, which included the following important changes:

- The amended requirements recognize that pipeline natural gas contains negligible amounts of nitrogen. Therefore, if the permittee elects to not use an allowance for fuel bound nitrogen, then there is no requirement for monitoring the nitrogen content of natural gas. This means that the permittee must use an "F-value" of "zero" when calculating the allowable NSPS Subpart GG NOx standard for the gas turbine. This change basically incorporates similar case-by-case determinations made over the years.
- The amended requirements also recognize that pipeline natural gas contains negligible amounts of sulfur. Therefore, if the permittee demonstrates that the maximum sulfur content of the pipeline natural gas is no more than 20 grains per 100 cubic feet of gas as specified in the current tariff sheet, then there is no requirement for monitoring the sulfur content of natural gas.
- Engine 1806 "dry" lean premix combustors and not wet injection to control NOx emissions. So, the continuous monitoring requirements for the water-to-fuel ratio are not appropriate. The Subpart GG NOx standard is 190 ppmvd @ 15% oxygen. This is nearly eight times the NOx standard of 25 ppmvd @ 15% oxygen specified in the permit. It would be nearly impossible for the lean premix gas turbine to exceed the NSPS Subpart GG NOx standard. The current permit does not require any continuous demonstration that the gas turbine is complying with the NSPS Subpart GG NOx standard. As stated in the preamble to the July 2004 amendments, the changes do not impose any additional monitoring for existing units.

FGTC agrees to use no allowance for fuel bound nitrogen when determining compliance with the NSPS Subpart GG NOx standard and has provided the current tariff sheet showing a maximum sulfur content of only 10 grains per 100 cubic feet of pipeline natural gas. The permit includes these and conditions. Therefore, monitoring for fuel nitrogen and sulfur is not required for the pipeline natural gas. The Department will remove the custom fuel monitoring plan and revise the permit to reflect these changes. No changes were made with regard to continuous monitoring for purposes of reporting excess NOx emissions; however, the permitting note was updated.

5. REQUIREMNTS FOR FUNCTIONALLY EQUIVALENT COMPONENT REPLACEMENTS

Executive Summary

Florida Gas Transmission Company (FGTC) operates several compressor stations serving a large natural gas pipeline that runs throughout Florida. The pipeline supports a wide variety of residential, commercial, industrial, and utility customers that rely on natural gas as a clean fuel. FGTC considers the months of April through October to be the critical "run season" for the gas pipeline. This is the period of highest expected natural gas use in Florida with compressor stations operating at higher rates than at other times of the year. During the run season, it is critical that repairs and maintenance be performed as quickly as possible to maintain natural gas availability throughout the system.

Many compressor stations use light industrial gas turbines to drive compressors that maintain pipeline pressure and flow. These types of gas turbines require relatively frequent inspections and maintenance to keep units in proper working order. Such maintenance activities are necessary to prevent the catastrophic failures, which would result in costly repairs and reduce reliability of the natural gas supply. The natural gas pipeline industry has determined that it is more efficient to perform certain repairs and maintenance activities at a regional maintenance facility as opposed to performing them on site. FGTC requests the Department's concurrence that pulling the gas generator component of Engine 1806, sending it to a regional maintenance facility for repair, and installing a like-kind gas generator, is not a modification and does not require a preconstruction permit.

The Bureau of Air Regulation concludes that replacement of the gas generator/power turbine component (or smaller components) for this light industrial gas turbine compressor engine is standard industry practice for the natural gas pipeline industry. As such, the replacement is not a modification and does not require a new air construction permit or modification of an existing air construction permit. This would also be true for comparable replacements for other gas turbines serving as compressor engines and having similar functions, characteristics, and sizes (< 16,000 bhp). This report presents background information for compressor station gas turbines, regulatory requirements, emissions impacts, maintenance practices, interpretations by other states, and the Bureau of Air Regulation's rationale for this conclusion.

Background

Engine 1806 is a permitted gas turbine compressor engine rated at approximately 7200 bhp. It is installed at Station 18, which is located Orlando, Orange County, Florida. In summary, FGTC requests the Department's concurrence that replacement of the gas generator component is standard practice for the gas pipeline industry and does not require a preconstruction permit. FGTC will provide notification of such replacements and compliance test the replacement unit with 60 days of first fire.

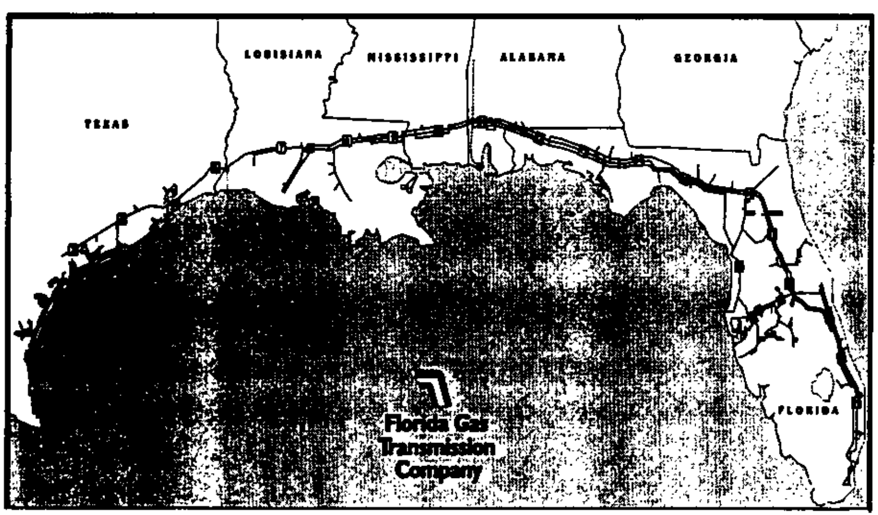

Figure 1. Existing Natural Gas Pipeline System

Florida Compressor Stations

No.	City	County
12	Milton	Santa Rosa
13	Caryville	Washington
14	Quincy	Gadsden
15	Perry	Taylor
16	Brooker	Bradford
17	Silver Springs	Marion
18	Orlando	Orange
19	Melbourne	Brevard
20	Ft. Pierce	St. Lucie
21	West Palm Bch	Palm Beach
24	Trenton	Gilchrist
26	Lecanto	Citrus
27	Thonotosassa	Hillsborough
30	Plant City	Hillsborough
31	Kissimmee	Osceola

FGTC operates and maintains a natural gas pipeline that has been in existence since 1958. As shown in Figure 1, the pipeline originates in Texas and passes through portions of Louisiana, Mississippi, Alabama, Georgia, and Florida. Compressor stations form an integral part of the pipeline system, providing the necessary pressure and flow to reliably deliver natural gas to residential, commercial, industrial, and electric utility consumers. There are fifteen existing compressor stations in Florida.

Each compressor station consists of a variety of equipment such as gas compressors, compressor engines, emergency generators, lube oil tanks, used oil tanks, and blow-down stacks. The main sources of air pollution are the compressor engines, which are either reciprocating internal combustion engines or light industrial aero-derivative gas turbines. These units provide the motive power necessary to drive the gas compressors, which boost pipeline pressure and allow flow throughout the system. All of the compressor engines fire natural gas as the exclusive fuel because of its ready availability along the pipeline. Reciprocating internal combustion engines vary in size from about 2000 to 4600 bhp output. Light industrial gas turbines provide much higher outputs ranging from about 1000 to 16,000 bhp output.

Gas Turbine Components

In recent years, FGTC began depending on light industrial aero-derivative gas turbines (< 16,000 bhp) for its compressor engines rather than reciprocating internal combustion engines. The new gas turbines are more powerful, more efficient, and emit less than one-tenth of the NOx emissions based on a comparable heat input rate. Each gas turbine is delivered to the station as a skid-mounted package consisting of the following general components: gas generator, accessory drive system, air inlet and filtration system, fuel delivery system, cooling system, lubrication system, power turbine, power shaft, control system, starting system, and exhaust system with stack. See Figure 2.

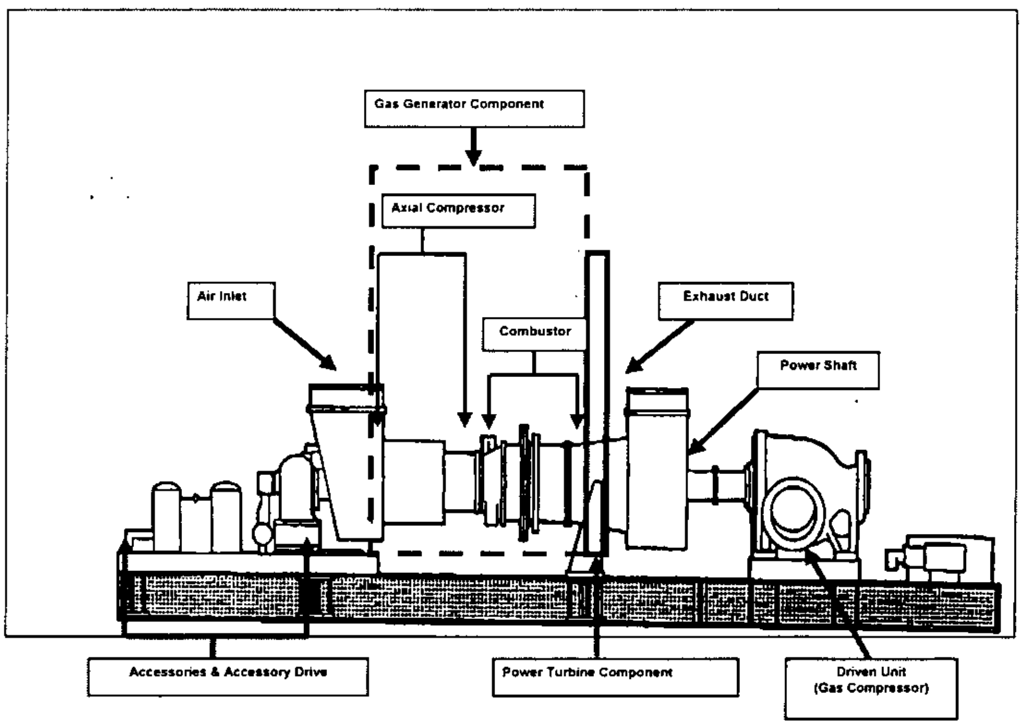

Figure 2. Gas Turbine Compressor Engine and Components

Gas turbines are designed to strict tolerances that must be maintained to ensure efficient operation and to prevent catastrophic failure of the components. Performing maintenance on many of these critical components is difficult and costly to perform in the field. To facilitate maintenance and repair, manufacturers of light industrial aero-derivative gas turbines typically incorporate a modular design to allow pulling and replacing component parts instead of performing maintenance in the field. Due to their relatively small size, replacement components can be quickly delivered and installed to minimize downtime. The "replaced component" is shipped back to a regional maintenance facility where it is overhauled and returned to a pool of similar gas turbine components to be used as a replacement in the future. For this reason, gas turbine manufacturers also provide extensive maintenance contracts with "pull and replace" provisions for "like-kind" components. Typical operating levels between major maintenance inspections and overhauls can be between 20,000 and 40,000 engine hours or less. This would be in the range of two to six years for a scheduled major overhaul required by the manufacturer.

Emissions from Gas Turbine Compressor Engines

Engine 1806 is a Royce Model No. 501-KC7 DLE gas turbine serving as a compressor engine at existing Station 18. Firing natural gas as the exclusive fuel, this unit has a nominal output capacity of approximately 7200 bhp at ISO conditions. It also incorporates a version of lean premix combustion technology, which results in low emissions of carbon monoxide (CO), nitrogen oxide (NOx), and volatile organic compounds (VOC). As natural gas contains little ash or sulfur, this unit also emits very low levels of particulate matter (PM/PM_{10}) and sulfur dioxide (SO_2). Table 1 shows the permitted potential emissions from Engine 1806.

Table 1. Potential Emissions from Engine 1806

Pollutant	Emission Factor Reference	Emission Factors		Emissions	
		Factor	lb/MMBtu	lb/hour	TPY
CO	Vendor	50 ppmvd @ 15% O_2	0.101	6.9	30
NOx	Vendor	25 ppmvd @ 15% O_2	0.082	5.7	25
PM/PM_{10}	AP-42, Table 3.1-2A	0.0066 lb/MMBtu	0.007	0.5	2
SO_2	FERC	10 grains sulfur/100 scf	0.028	1.9	8
VOC	Vendor	0.2 lb/hour	0.003	0.2	1

Notes:

a. Emission rates are based on a maximum heat input rate of 68 MMBtu/hour and a compressor inlet temperature of 59° F.

b. Annual emissions are based on year-round operation (8760 hours per year) at these rates.

c. "FERC" is the Federal Energy Regulatory Commission. FERC establishes the maximum sulfur content for pipeline gas.

Review

The Bureau of Air Regulation uses numerous criteria to determine whether or not repair, replacement, or maintenance activities are considered routine. Many of these items are interrelated and no one factor determines whether a project is routine or not. Instead, these factors are reviewed in light of the specific case and available information to reach a conclusion for the project as a whole. The Department reviewed the following key areas with regard to the replacement of a gas generator/power turbine component in a light industrial aero-derivative gas turbine compressor engine serving a natural gas pipeline. It is also worth noting that if the industry were performing these maintenance and repair activities in the field at each site, the Department does not believe a construction permit would be necessary.

Nature

1. Are major components of a facility are being modified or replaced? Specifically, are the units of considerable size, function, or importance to the operation of the facility, considering the type of industry involved?

   Gas turbine compressor engines are a major part of a natural gas compressor station and serve to fulfill the primary function. In terms of the entire natural gas pipeline, a single gas turbine compressor engine might be considered rather small. Currently, the largest gas turbine compressor engine is 15,700 bhp, which is equivalent to approximately 12 MW. The gas generator is the major component of a gas turbine compressor engine.

2. Does the change require pre-approval of a state commission, in the case of utilities?

Pipelines and compressor station projects must get prior approval based on need from the Federal Energy Regulatory Commission (FERC). Once the original site and capacity is approved, specified equipment may be replaced as necessary without additional approval from FERC. With regard to the state, gas turbines are primarily approved for construction through the Department's air permitting process. Any changes that would increase or decrease capacity would require additional air construction permits and would likely require prior approval from FERC.

3. Does the source itself characterize the change as "non-routine" in any of its own documents?

   FGTC contends that it is *not* typical to perform most repairs for a gas generator *on site*. For the gas pipeline industry, it is more common to remove the component and transport it to a central maintenance facility for repair. Because repair can take several weeks or months, a replacement gas generator is usually installed to minimize downtime during periods of high demand. FGTC provided a discussion of maintenance practices from Solar Gas Turbines, a company that manufactures many of the existing units. This document describes the replacement of a gas generator component as a standard industry maintenance practice for its aero-derivative, light industrial gas turbines. Such units are designed to strict tolerances that must be maintained to ensure efficient operation and prevent catastrophic failure of the components. Performing maintenance on many of these critical components is difficult and costly to perform on site. Therefore, light industrial gas turbines incorporate a modular design to facilitate prompt repair and return to service.

   Based on the modular design, equipment manufacturers are able to offer comprehensive maintenance contracts to "pull and replace" components and eliminate critical downtime. The faulty equipment is replaced with a like-kind component, transported to a regional maintenance facility, repaired, and returned to a pool of available replacement components. Downtime for the gas turbine compressor engine may be just a few days even for the replacement of the gas generator component. Solar Gas Turbines indicates that more than 85% of the gas generators and gas generator/power turbine sets leaving their central maintenance facility are considered "replacement components".

4. Can the change be performed during full functioning of the facility or while it is in full working order?

   Gas generator repairs cannot generally be performed while the unit is in operation. As discussed previously, the exacting tolerances make on site repair difficult and costly. Replacements can usually be installed within a few days.

5. Are the materials, equipment and resources necessary to carry out the planned activity already on site?

   No, replacement components are generally warehoused with the original equipment vendor. Under a maintenance contract, a replacement component (even an entire gas generator) can be delivered within a day or so. The malfunctioning component is then pulled and returned to the equipment vendor for repair. A replacement component is installed so that the compressor engine can return to service. If the gas turbine is still under the initial warranty, a repaired component is occasionally returned back to the original compressor station and re-installed as the original equipment. This is based on specific contractual requirements and may be at the discretion of the equipment vendor.

<u>Extent</u>

1. Will an entire emissions unit be replaced?

   The entire gas turbine compressor engine is not being replaced, but the gas generator is a major component of the gas turbine compressor engine. However, the modular design of the light industrial, aero-derivative gas turbine allows the rapid replacement of even this large component.

2. Will the change take a significant time to perform?

   Generally, replacement of a gas generator component can be completed in just a few days. This is the main reason for development of the "pull and replace" policy for handling maintenance and repair issues.

3. Will the collection of activities, taken as a whole, constitute a "non-routine effort", notwithstanding that individual elements could be routine?

   For a light industrial aero-derivative gas turbine, manufacturers normally recommend a major overhaul every two to six years depending on the model and actual operating hours. An overhaul generally involves complete refurbishment of the gas generator to restore it to the original design and operating specifications. For the gas pipeline industry, such overhauls are typically performed at a regional maintenance facility. Alternatively, it is possible that the smaller individual components could be replaced during this period, which would eventually result in near replacement of the gas generator.

   EPA's background document for NSPS Subpart GG (EPA-450/2-77-017a) notes that the terms "overhaul" and "ultimate life" are not defined equally by all gas turbine manufacturers. This makes it difficult to distinguish between modifications and routine maintenance practices. It mentions that non-wearing parts (rotor discs, casings, housing, bearing supports, rotor shafts, etc.) are designed for an ultimate life of about 30 years. However, most manufacturers require "overhauls" after about 20,000 to 40,000 hours of operation. Because an overhaul typically returns a unit to "new" condition, the "ultimate life" of the gas turbine may be indefinite.

   The EPA document specifically lists several changes that would *not* be modifications: relocation or transfer of ownership; changes in types or grades of fuel if originally designed for its use; increases in operating hours; variations in operating loads within the original engine design specification; and routine repairs, like-kind replacements, and maintenance (including the repair or replacement of stator blades, turbine nozzles, turbine buckets, fuel nozzles, combustion chambers, seals, and shaft packings). Note that the list of gas turbine components represents parts of the gas generator. The EPA document also lists the following changes that could be modifications resulting in increased emissions: replacements with a different design that allows the firing of alternate fuels; replacements with a different design that allows increased power output; and operating the unit at higher sustained outputs than the original design. The purpose of listing activities that would or would not be a "modification" that would trigger the NSPS Subpart GG requirements was to show that the new regulation would have only slight impacts on existing gas turbines based on existing practices.

4. Does the change require the addition of parts to existing equipment?

   No, gas generator components are replaced with functionally equivalent "like-kind" components. Occasionally, manufacturers improve replacement parts to resolve continuing maintenance problems. However, such improvements would not increase the maximum heat input rate or output capacity. Capacity increases require new air permits and would likely require a new FERC approval.

<u>Purpose</u>

1. Is the purpose of the effort to extend the useful life of the unit? Does the owner propose to replace a unit at the end of its useful life?

   The primary purpose of component replacement is to facilitate prompt repair in order to return the gas turbine compressor engine to its original design and operating specifications. FGTC believes that component replacement does not increase the operating life of the gas turbine beyond that of a unit that was "properly maintained" in the field. It is noted that such replacements may lead to an "indefinite" life for the gas turbine.

2. Will the change keep the unit operating in its present condition or will it allow enhanced operation? Will the change permit increased capacity, operating rate, utilization, or fuel adaptability?

   Replacement of the gas generator component with a functionally equivalent "like-kind" component will allow the compressor engine to continue operating as it was originally designed. The replacement is not intended to increase the capacity, operating rate, or utilization of the compressor engine. These units typically operate a significant portion of each calendar year (> 40%) depending entirely on consumer demands for natural gas. For this reason, gas turbine compressor engines are typically permitted for year round operation (8760 hours per year). Because compressor engines serve a natural gas pipeline, natural gas is the exclusive fuel and fuelswitching is not an issue.

Frequency: Is the change performed frequently in a typical unit's life?

Yes, it is possible that a gas generator replacement will be performed many times over the life of a gas turbine compressor engine. Again, equipment manufacturers purposely incorporate modular designs into their light industrial, aero-derivative gas turbines to allow for quick component replacements rather than on-site maintenance. Such designs lead to long-term maintenance contracts that include regularly scheduled replacements. Although the "changes" may occur relatively frequently, these practices are intended to keep the unit operating as originally designed.

Cost

1. Will the change be costly, both in absolute terms and relative to the cost of replacing the unit?

Replacement of a gas generator is likely the most expensive single component replacement. However, the true cost of such a replacement is difficult to estimate accurately. First, replacements are typically performed in accordance with current contractual requirements, which may cover an entire fleet of gas turbines. So, replacement costs may be spread over a large number of similar units. Second, when a replacement gas generator is installed, the original gas generator retains some value. Typically, the "replaced" gas generator is shipped to a regional maintenance facility for repair. After an overhaul and performance testing, the "replaced" unit returns to a fleet of similar equipment, which will be used as "replacement" components. As summarized in the following table, FGTC provided the following information as an estimate of the component costs for a typical light industrial gas turbine.

Table 2. Estimated Component Costs for a New Light Industrial Gas Turbine (Solar Mars 110S)

Gas Generator (Air Intake Assembly, Combustion Assembly, Compressor Assembly and Gas Producer Turbine Assembly)	$2,400,000
Power Turbine (Power Turbine Rotor Assembly, Turbine Exhaust Diffuser, Control System and Inlet Filter and Silencer)	$600,000
Ancillary Components (Exhaust Collector and Silencer, Control and Electrical System, Starter Assembly, Accessory Drive, Fuel Control System, Lube Oil Coolers, and Lube Oil Skid)	$3,000,000
Miscellaneous Costs Engineering and Design, Construction Management, Foundations and Supports and Installation)	$3,000,000
Total Capital Cost	$9,000,000

The capital costs of the gas generator plus power turbine ($3 million) represent approximately 33% of the total capital cost of a new gas turbine ($9 million). The estimated "*replacement cost*" for a gas generator plus power turbine from the replacement pool is approximately $300,000. This represents only 10% of the estimated costs for brand new components and less than 5% of the total estimated cost of a new gas turbine compressor engine.

2. Is a significant amount of the cost of the change included in the source's capital expenses, or will the change be paid for out of the operating budget? Are the costs reasonably reflective of the costs originally projected during the unit's design phase as necessary to maintain day-to-day operation?

Any costs related to component replacements that are covered under the original warranty would be charged to the operating budget. Any components sent off site for repair and returned to the original site are charged to the operating budget. Any replacement costs incurred for the newest Nuovo-Pignone gas turbines (15,700 bhp) are charged to the operating budget. Replacement costs for out-of-warranty units are charged to the capital budget. As previously discussed, these replacement costs are well known in the design phase and planned for accordingly.

How do other states handle component replacements?

The pipeline originates in Texas and passes through portions of Louisiana, Mississippi, Alabama, and Florida. Alabama considers like-kind component replacements to be "routine", as do several other states that have natural gas pipelines including Georgia, Minnesota, Montana, North Dakota, and South Dakota. Louisiana requires a "minor modification", which involves a $140 permit fee and a 4-page application. A public notice is not required and permit modifications are typically issued within 5-6 days of submittal. For units with NOx emissions less than 25 TPY, Texas allows the exchange of gas turbines under a "Permit by Rule" with no notice requirements. It appears that all of the pipeline compressor engines in Texas are in this category.

Conclusion

The primary purpose of a "like-kind" gas generator component replacement is to facilitate prompt repair in order to return the gas turbine compressor engine to its original design and operating specifications. Manufacturers purposely incorporate a modular design into light industrial gas turbines (< 16,000 bhp) to simplify component replacements and allow the gas turbine compressor engine to quickly return to service. After review of the available information, the Bureau of Air Regulation concludes that replacement of the gas generator component of gas turbine compressor Engine 1806 is a routine maintenance practice for the natural gas pipeline industry.

Rule 62-210.300(1)(a), F.A.C. states that, "Unless exempt from permitting pursuant to Rule 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., an air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification, in accordance with all applicable provisions of this chapter, Chapter 62-212, F.A.C., and Chapter 62-4, F.A.C." Rule 62-210.200(169), F.A.C. defines a *modification* as, "Any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any air pollutant subject to regulation under the Act, including any not previously emitted, from any emissions unit or facility." However, it also states that, "A physical change or change in the method of operation shall not include ... routine maintenance, repair, or replacement of component parts of an emissions unit ..."

By definition, it is not a modification to perform routine repairs, replacements, and maintenance on permitted units. Therefore, replacement of the gas generator does not require a new air construction permit or a modification to the initial air construction permit. Because the gas generator is the largest component having the greatest impact on emissions, the conclusion would be the same for smaller individual components. This would also be true for comparable replacements on other gas turbines serving as compressor engines at this station and having similar functions, characteristics, and sizes (< 16,000 bhp). The Bureau of Air Regulation's conclusion is specific to light industrial aero-derivative gas turbine compressor engines and shall not be used for any other sizes of gas turbines, uses of gas turbines, other types of emissions units or for any other industries.

Rule 62-4.160(2) and (6), F.A.C. requires an owner to provide information regarding changes made to permitted equipment. For cases related to repair, Rule 62-4.130, F.A.C. requires this notification to be made promptly once the equipment has failed, or is identified as subject to failure, and is scheduled for replacement. Rule 62-4.160(15), F.A.C. requires a permittee to provide information that shows compliance with the terms of its permit. Rule 62-297.310(7)(b), F.A.C. gives the Department the authority to require tests following maintenance to show that the repaired unit remains in compliance with all established emission limits. Such tests will also verify that there are no deviations from the permit conditions or emission limits as a result of the replacement. Based on these regulations, the following process is recommended to clarify notification and testing requirements for gas generator component replacements.

"For the replacement of gas turbine components to facilitate prompt repair and return the unit to its original specifications, the permittee shall comply with the following notification and testing requirements.

1. Components shall only be replaced with functionally equivalent "like-kind" equipment. Replacement

components may consist of improved or newer equipment, but such components shall not change operation or increase the capacity (heat input rate or power output) of the gas turbine. Replacement components that affect emissions shall be designed to achieve, and shall achieve, the emissions standards specified in all valid air permits or better. After a component replacement, the gas turbine remains subject to the standards of all valid air permits. [Rule 62-210.200(169), F.A.C.]

2. For gas generator replacements, the permittee shall notify the Compliance Authority within seven days of beginning such work. Within seven days of first fire on a replacement gas generator, the permittee shall submit the following information to the Compliance Authority: date of first fire and certification from the vendor that the replacement gas generator is a functionally equivalent "like-kind" component. The vendor certification shall also identify the make, model number, maximum heat input rate (MMBtu/hour), power output (bhp) at ISO conditions, and that the permitted emission rates are achievable with the replacement component. This notification may be made by letter, fax, or email. A copy of this information shall be kept on site at the compressor station. Within 60 days of restarting the unit after a gas generator replacement, the permittee shall conduct stack tests to demonstrate compliance with the applicable emission standards. The permittee shall notify the Compliance Authority in writing at least 15 days prior to conducting these tests. The permittee shall comply with all permit requirements for test notification, test methods, test procedures, and reporting. [Rules 62-4.130, 62-4.160(2), (6), and (15) and 62-297.310(7)(b), F.A.C.]

3. After investigation and for good cause, the Department may require special compliance tests pursuant to Rule 62-297.310(7)(b), F.A.C."

The above provisions ensure that the replacements are "like-kind", that the repaired emissions unit complies with the emissions standards, and that the appropriate Compliance Authorities are kept informed.

Does this impact NSPS Subpart GG requirements?

This gas turbine compressor engine is currently subject to NSPS Subpart GG, which regulates emissions of nitrogen oxides and sulfur dioxide from stationary gas turbines. However, this unit is permitted at much lower levels and readily complies with the NSPS requirements. In fact, FGTC has few (if any) pre-NSPS units in operation along their natural gas pipeline. Even so, the replacement gas generator component is intended to return the unit to original design and operating specifications and will not increase the unit capacity. Consequently, there will be no increase in hourly emissions that could trigger new Subpart GG requirements. In addition, available information suggests that the cost of replacing the entire gas generator/power turbine set is much less than the 50% replacement cost criteria that would trigger "reconstruction" under the NSPS requirements. Therefore, such replacements do not affect the applicability for, or compliance with, the NSPS Subpart GG requirements.

Does this impact NESHAP Subpart YYYY requirements?

About half of FGTC's existing compressor stations are major sources of hazardous air pollutants. According to the recently promulgated NESHAP, new gas turbines constructed after January 14, 2003 at these major facilities are subject to the Subpart YYYY requirements. Several existing gas turbines constructed before January 14, 2003 at these major facilities are considered "affected sources", but are not subject to any specific requirements. Such existing units could become subject to the same requirements for new units if "reconstructed". However, Subpart YYYY also uses the 50% replacement cost criteria to define "reconstruction". Again, it is unlikely that any routine component replacements would trigger "reconstruction". Therefore, such replacements do not affect the applicability for, or compliance with, the NESHAP Subpart YYYY requirements.

Does this impact PSD applicability?

About half of FGTC's existing compressor stations are PSD-major facilities. PSD preconstruction review could possibly apply to existing units undergoing a modification. However, replacement of the gas generator component of a light industrial gas turbine compressor engine is considered a routine maintenance practice for the gas pipeline industry. By definition, it is not a modification to perform routine repairs, replacements, and maintenance on permitted units. Therefore, such replacement activities are not subject to PSD review.

Other Considerations

Over the lasts several years, the Department has issued many permits authorizing the construction and operation of new large frame (~ 40 to 170 MW) gas turbines at electrical generating plants. The Department does not believe that replacing the gas generator component for these large frame units is routine maintenance. However, the determination of Best Available Control Technology for many of the large frame gas turbine projects relied on clean burning natural gas as the primary fuel to achieve the lowest levels of emissions. The backup fuel for these units is distillate oil, which results in far more pollution. Therefore, quick component replacements for FGTC's small compressor engines will help ensure that a reliable supply of natural gas is available for use at large power plants.

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the specific conditions of the draft permit. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Florida Gas Transmission Company
P. O. Box 4657
Houston, TX 77101-4657

Authorized Representative:
Mr. Richard Craig, V.P. of Southeastern Operations

Draft Air Permit No. 0950190-006-AC
Compressor Station 18
Increased Heat Input for Engine 1806
Orange County, Florida

Facility Location: Florida Gas Transmission Company operates existing Compressor Station 18, which is located at 7990 Steer Lake Road in Orlando, Florida.

Project: The applicant proposes to revise the original air construction permit for Engine 1806 to increase the maximum heat input rate, include notification/testing requirements for functionally equivalent component replacements, and to make the fuel monitoring requirements consistent with the recent amendments to NSPS Subpart GG for gas turbines. Details of the project are provided in the in the application and the enclosed "Technical Evaluation and Preliminary Determination".

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is 111 South Magnolia Drive, Tallahassee, Florida. The Permitting Authority's mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above. A copy of the complete project file is also available at the Air Resources Section of the Department's Central District Office at 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of fourteen (14) days from the date of publication of the Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/3/04 to the persons listed below.

Mr. Richard Craig, FGTC*
Mr. James Fleak, FGTC
Mr. David H. Parham, P.E., FGTC
Mr. V. Duane Pierce, AQMcs
Mr. Len Kozlov, CD
Ms. Marie Driscoll, OCEPD

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 11/3/04 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Draft Air Permit No. 0950190-006-AC
Florida Gas Transmission Company – Existing Compressor Station 18
Orange County, Florida

Applicant: The applicant for this project is the Florida Gas Transmission Company. The applicant's mailing address is: P. O. Box 4657, Houston, TX 77101-4657. The applicant's authorized representative is Mr. Richard Craig, the V.P. of Southeastern Operations.

Facility Location: The Florida Gas Transmission Company operates existing Compressor Station 18, which is located at 7990 Steer Lake Road in Orlando, Florida.

Project: The applicant proposes several revisions to the original air construction permit for Engine 1806. As installed, the gas turbine fires slightly more natural gas to produce the required power output. The applicant requests approximately an 8% increase in the maximum heat input rate. Also, Engine 1806 is a light-industrial gas turbine with a power output of approximately 7200 bhp. It is common practice within the gas pipeline industry to replace the gas generator for maintenance and repair with a functionally equivalent component. The replaced gas generator is then shipped to a regional facility for maintenance and placed back into a pool of similar components. The applicant requests specific notification and testing requirements for conducting such functionally equivalent component replacements. Finally, EPA recently amended the federal fuel monitoring requirements for nitrogen and sulfur in Subpart GG of 40 CFR 60 regulating gas turbines. The applicant requests a permit revision to be consistent with the amended fuel monitoring requirements.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination regarding this project. The Permitting Authority's physical address is 111 South Magnolia Drive, Tallahassee, Florida. The Permitting Authority's mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Air Resources Section of the Department's Central District Office at 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit for a period of fourteen (14) days from the date of publication of this Public Notice. Written comments must be provided to the Permitting Authority at the above address. Any written comments filed will be made available for public inspection. If written comments received result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial rights will be affected by the agency determination; (c) A statement of how and when the petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available for this proceeding.

DRAFT PERMIT REVISION

PERMITTEE:

Florida Gas Transmission Company
P. O. Box 4657
Houston, TX 77101-4657

Authorized Representative:
Mr. Richard Craig, V.P. of Southeastern Operations

Orlando Compressor Station 18 Air Permit No. 0950190-006-AC Facility ID No. 0950190 SIC No. 4922 Expires: July 1, 2005

DESCRIPTION AND LOCATION

Existing Station 18 consists of the following six compressor engines.

ID	Emission Unit Description
001	Engine 1801 is a 2000 bhp reciprocating internal combustion engine installed in 1962.
002	Engine 1802 is a 2000 bhp reciprocating internal combustion engine installed in 1962.
003	Engine 1803 is a 2000 bhp reciprocating internal combustion engine installed in 1962.
004	Engine 1804 is a 2000 bhp reciprocating internal combustion engine installed in 1968.
005	Engine 1805 is a 2700 bhp reciprocating internal combustion engine installed in 1991.
006	Engine 1806 is a 7200 bhp (ISO) gas turbine installed in 2003.

This permit establishes requirements for Emissions Units 005 and 006 at existing Compressor Station 18, which is located at 7990 Steer Lake Road in Orlando, Florida. It is a revision of original air construction Permit No. 0950190-004-AC. The UTM coordinates are Zone 17, 451.86 km East, and 3154.79 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 60 of the Code of Federal Regulations. The permittee is authorized to perform the work and make the proposed changes 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

SECTION 1. GENERAL INFORMATION

PROJECT DESCRIPTION

Engine 1806 was installed under original air construction Permit No. 0950190-004-AC as a new 7200 bhp gas turbine to be used as a compressor engine at existing Compressor Station 18. That permit also included a revision of the particulate matter emissions standard for Engine 1805, an existing reciprocating internal combustion engine used as a compressor engine at Station 18. Air Permit No. 0950190-006-AC is issued as a revision of the original air construction permit to: authorize a nominal increase in the maximum heat input rate for Engine 1806; include notification and recordkeeping requirements for functionally equivalent component replacements on Engine 1806; and revise the fuel nitrogen and sulfur monitoring requirements to be consistent with recent amendments to NSPS Subpart GG for gas turbines.

REGULATORY CLASSIFICATION

Title III: The facility is a major source of hazardous air pollutants (HAP).

Title IV: The facility has no units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution (Chapter 213, F.A.C.).

PSD: The facility is a PSD-major source of air pollution (Rule 62-212.400, F.A.C.).

NSPS: The gas turbine is subject to the New Source Performance Standards in Subpart GG of 40 CFR 60.

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.

- Application No. 0950190-006-AC received on 09/10/04 and all related correspondence.
- Administrative correction to Air Permit No. 0950190-004-AC issued on 04/15/04.
- Extension to Air Permit No. 0950190-004-AC issued on 11/05/03.
- Air Permit No. 0950190-004-AC issued on 01/10/03, which authorized initial construction of Engine 1806.
- Air Permit No. PSD-FL-163 issued on 05/09/91, which authorized initial construction of Engine 1805.

1. Permitting Authority: All documents related to applications for permits to construct or modify a PSD-major source 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. All documents related to applications for operation permits shall be submitted to the Air Resources Section of the Department's Central District Office at 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to: Air Quality Management, Orange County Environmental Protection Division, 800 Mercy Drive, Suite 4, Orlando, FL 32808.

3. Appendices: The following Appendices are attached as part of this permit: Appendix CF (Citation Format); Appendix GC (General Conditions); Appendix GG (NSPS Subpart GG Requirements for Gas Turbines); and Appendix SC (Standard Conditions).

4. 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, F.S.; Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.; and Title 40, Part 60 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.]

5. 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.]

6. 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.]

7. Authority to Construct: The emissions units regulated by this air construction permit have been constructed and are in operation. No further construction is authorized.

8. Title V Permit: Pursuant to Rule 62-213.420(1)(a)2, F.A.C., the permittee shall submit an application for a revised Title V air operation permit at least ninety (90) days before the expiration of this permit, but no later than 180 days after commencing operation. In accordance with Rule 62-213.412(2), F.A.C., the permittee may immediately implement the changes authorized by this air construction permit after submitting the application for a revised Title V air operation permit to the Permitting Authority and providing copies of the application to EPA Region 4 and each Compliance Authority. To apply for a revised 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 Central District Office with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, 62-213.412, and 62-213.420, F.A.C.]

A. EU-005 - 2700 bhp Compressor Engine No. 1805

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

Emissions Unit No. 005 - Compressor Engine No. 1805
The existing compressor engine is a 2700 bhp reciprocating internal combustion engine fired exclusively with pipeline natural gas.

APPLICABLE REQUIREMENT

1. Previous Permits: This permit supplements all previously issued air construction and operation permits for this emissions unit. Except for the change noted below, the unit remains subject to the conditions of all other valid air construction and operations permits. [Rule 62-4.070, F.A.C.]

2. Particulate Matter: For Compressor Engine No. 1805 (EU-005), particulate matter emissions are minimized by good combustion design with the firing of natural gas as the exclusive fuel. This requirement supersedes the particulate matter standards (TSP and PM_{10}) in Condition No. 1 of Air Permit No. PSD-FL-163, as amended. *{Permitting Note: This change does not result in any increases in actual or potential emissions of particulate matter. All other standards of Air Permit No. PSD-FL-163 remain unaffected.}*

B. EU-006 - 7200 bhp Compressor Engine No. 1806

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

Emissions Unit No. 006 - 7200 bhp Compressor Engine No. 1806
Description: The compressor engine is a 7200 bhp (ISO) gas turbine consisting of a Cooper-Rolls Royce Model No. 501-KC7 DLE with lean premix combustor design.
Fuel: The gas turbine fires pipeline natural gas (SCC No 2-02-002-01) at a maximum firing rate of approximately 65,100 cubic feet per hour based on a heat content of 1040 BTU per SCF of gas.
Capacity: At ~~63~~ 68 MMBtu per hour of heat input, the gas turbine produces approximately 7200 bhp (ISO). The gas turbine typically operates near capacity.
Controls: The lean premix combustor design minimizes NOx emissions. The efficient combustion of natural gas at high temperatures minimizes emissions of CO, PM/PM_{10}, SO_2, and VOC.
Stack Parameters: When operating at capacity, exhaust gases exit a 6.0 feet diameter stack that is 61.2 feet tall at 964° F with a flow rate of approximately 97,500 acfm.

APPLICABLE STANDARDS AND REGULATIONS

1. NSPS Requirements: The gas turbine shall comply with the New Source Performance Standards (NSPS) of Subpart GG in 40 CFR 60. The applicable NSPS requirements are provided in Appendix GG of this permit. The Department believes that the conditions in this section are at least as stringent as, or more stringent than, the NSPS requirements of Subpart GG. [Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subpart GG]

EQUIPMENT

2. Compressor Engine No. 1806: The permittee is authorized to install one 7200 bhp (ISO) gas turbine compressor engine consisting of a Cooper-Rolls Royce Model No. 501-KC7 DLE. The permittee shall tune, operate and maintain the gas turbine's lean premix combustor design to reduce emissions of nitrogen oxides below the permitted limits. Ancillary equipment includes the automated gas turbine control system, an inlet air filtration system, and an exhaust stack. [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

3. Permitted Capacities: The maximum heat input rate to the gas turbine shall not exceed ~~63~~ 68 MMBtu per hour (24-hour average) while producing approximately 7200 bhp (ISO) based on a compressor inlet air temperature of 59° F, 100% load, and a higher heating value (HHV) of 1040 BTU per SCF for natural gas. Heat input rates will vary depending upon gas turbine characteristics, load, and ambient conditions. 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 testing. Performance data shall be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. Compliance with this equipment specification shall be demonstrated based on the information required in Condition 13 of this subsection. [Rule 62-210.200(PTE), F.A.C.]
4. Authorized Fuel: The gas turbine shall fire only natural gas with a maximum of 10 grains of sulfur per 100 standard cubic feet of natural gas. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]
5. Restricted Operation: The hours of operation for the gas turbine are not limited (8760 hours per year). Except for startup and shutdown, operation below 50% base load is prohibited. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

6. Emissions Standards: Emissions from the gas turbine shall not exceed the following standards for carbon monoxide (CO), nitrogen oxides (NOx), opacity, particulate matter (PM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Pollutant	Standards	Equivalent Maximum Emissions [f]		Rule Basis [g]
		lb/hour	TPY	
CO [a]	50.0 ppmvd @ 15% O_2	6.9	30.22	Avoid Rule 62-212.400, F.A.C.
NOx [b]	25.0 ppmvd @ 15% O_2	5.7	24.97	Avoid Rule 62-212.400, F.A.C. 40 CFR 60.332
SO_2 [c]	10.0 grains of sulfur per 100 SCF of gas	~~1.7~~ 1.9	~~7.45~~ 8.15	Avoid Rule 62-212.400, F.A.C. 40 CFR 60.333
Opacity [d]	10% opacity, 6-minute average	Not Applicable		Rule 62-4.070(3), F.A.C.
PM [e]	Efficient combustion of natural gas	~~0.4~~ 0.5	~~1.75~~ 1.96	Rule 62-4.070(3), F.A.C.
VOC [e]	Efficient combustion of natural gas	0.2	0.88	Rule 62-4.070(3), F.A.C.

a. The CO standards are based on the average of three test runs as determined by EPA Method 10.

b. The NOx standards are based on the average of three test runs as determined EPA Method 20.

c. The fuel sulfur specification is based on the maximum limit specified by Federal Energy Regulatory Commission (FERC) and effectively limits the potential SO_2 emissions. Expected fuel sulfur levels are less than 1 grain per 100 SCF of natural gas from the pipeline.

d. The opacity standard is based on a 6-minute average, as determined by EPA Method 9.

e. For both PM and VOC, the efficient combustion of natural gas is indicated by compliance with opacity and CO standards. Equivalent maximum PM emissions are based on a factor of 0.0066 lb/MMBtu heat input from AP-42 Table 3.1-2a. Equivalent maximum VOC emissions are based on a total hydrocarbon factor of 1.58 lb/eng-hr from the vendor and the conservative assumption that 10% the hydrocarbons are regulated (non-methane) VOC. No testing is required.

f. Equivalent maximum emissions are based on the maximum expected emissions, permitted capacity, a compressor inlet air temperature of 59° F, and 8760 hours of operation per year. For comparison purposes, the permittee shall provide a reference table with the initial compliance test report of mass emission rates versus the compressor inlet temperatures. Each test report shall include measured mass emission rates for CO, NOx and SO_2. Mass emission rates for SO_2 shall be calculated based on actual fuel sulfur content and fuel flow rate. For tests conducted at 59° F or greater, measured mass emission rates shall be compared to the equivalent maximum emissions above. For tests conducted below 59° F, measured mass emission rates shall be compared to the tabled mass emission rates provided by the manufacturer based on compressor inlet temperatures.

g. Compliance with the emissions standards of this permit ensures that the project remains a minor source of air pollution with respect to PSD.

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Permitting Note: These methods shall be used as necessary to support other required methods.}*
9	Determination of Opacity
10	Determination of Carbon Monoxide Emissions *{Permitting Note: This method shall be based on a continuous sampling train.}*
19	Determination of Sulfur Dioxide and Nitrogen Oxides Emission Rates *{Permitting Note: This method shall be used as necessary to support other required methods.}*
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Gas Turbines

Tests shall be conducted in accordance with the requirements specified in Appendix SC of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

8. Initial Tests: The gas turbine shall be tested to demonstrate initial compliance with the emission standards for CO, NOx, and visible emissions. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the gas turbine. The initial NOx performance tests shall be conducted at approximately four evenly spaced points between the minimum normal operating load and 100% of peak load. Each of the three low-load NOx performance tests shall consist of three, 20-minute test runs. The peak load NOx performance test shall consist of three, 1-hour test runs. The CO performance tests shall be conducted concurrently with the NOx performance tests at peak load. SO_2 emissions shall be calculated and reported based on fuel flow and vendor analysis of fuel sulfur content. *{Permitting Note: Initial tests have already been performed for this unit and are not required to be repeated as part of this permit revision.}* [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 60.335]

9. Annual Tests: During each federal fiscal year (October 1 - September 30), the gas turbine shall be tested to demonstrate compliance with the emission standards for CO, NOx, and visible emissions. CO and NOx emissions shall be tested concurrently at permitted capacity. SO_2 emissions shall be calculated and reported based on fuel flow and vendor analysis of fuel sulfur content. In addition to the test results, each report shall include a general description of the maintenance activities and operation of this facility since the last test. [Rule 62-297.310(7)(a)4, F.A.C.]

10. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other subsequently required tests. [Rule 62-297.310(7)(a)9, F.A.C.; 40 CFR 60.7 and, 60.8]

RECORDS, REPORTS, AND NOTIFICATIONS

11. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix SC of this permit. In addition, NOx emissions shall be corrected to ISO ambient atmospheric conditions and compared to the NSPS Subpart GG standard identified in Appendix GG of this permit for each required test. For each test run, the report shall also indicate the natural gas firing rate (cubic feet per hour), heat input rate (MMBtu per hour), the power output (bhp), percent peak load, and the inlet compressor temperature. [Rule 62-297.310(8), F.A.C.; 40 CFR 60.334]

12. Fuel Monitoring: The gas turbine shall fire only pipeline natural gas with a maximum fuel sulfur content of no more than 10 grains of sulfur per 100 cubic feet of gas. The permittee shall take no allowance for fuel bound nitrogen (F-value = 0) when demonstrating compliance with the NSPS Subpart GG NOx standard. Based on these restrictions, no monitoring for the fuel nitrogen and sulfur contents is required. This is also described in Appendix GG of this permit. [Rule 62-4.070(3), F.A.C.; 40 CFR 60.334, as amended]

13. Operational Data: Using the automated gas turbine control system, the permittee shall monitor and record heat input (MMBtu), power output (bhp), and hours of operation for the gas turbine. Within the 10 days of a request by the Department or the Compliance Authority, the permittee shall be able to summarize the following information for a given day: heat input (MMBtu per hour, daily average); power output (bhp, daily average); and total hours of gas turbine operation. This information shall also be used for submittal of the required Annual Operating Report. [Rule 62-4.070(3), F.A.C.]

14. Component Replacements: For the replacement of gas turbine components to facilitate prompt repair and return the unit to its original specifications, the permittee shall comply with the following notification and testing requirements.

    a. Components shall only be replaced with functionally equivalent "like-kind" equipment. Replacement components may consist of improved or newer equipment, but such components shall not change operation or increase the capacity (heat input and power output rates) of the gas turbine. Replacement components that affect emissions shall be designed to achieve the emissions standards specified in all valid air permits and shall achieve these standards or better. After a component replacement, the gas turbine compressor engine remains subject to the standards of all valid air permits. [Rule 62-210.200(169), F.A.C.]

    b. The permittee shall notify the Compliance Authority within seven days after beginning any replacement of the gas generator component of the compressor engine. Within seven days of first fire on a replacement gas generator, the permittee shall submit the following information to the Compliance Authority: date of first fire and certification from the vendor that the replacement gas generator is a functionally equivalent "like-kind" component. The vendor certification shall also identify the make, model number, maximum heat input rate (MMBtu/hour), power output (bhp) at ISO conditions, and that the permitted emission rates are achievable with the replacement component. This notification may be made by letter, fax, or email. A copy of the information shall be kept on site at the compressor station. Within 60 days of restarting the unit after a gas generator replacement, the permittee shall conduct stack tests to demonstrate compliance with the applicable emission standards. The permittee shall notify the Compliance Authority in writing at least 15 days prior to conducting these tests. The permittee shall comply with all permit requirements for test notification, test methods, test procedures, and reporting. [Rules 62-4.130, 62-4.160(2), (6), and (15) and 62-297.310(7)(b), F.A.C.]

    c. After investigation and for good cause, the Department may require special compliance tests pursuant to Rule 62-297.310(7)(b), F.A.C.

CONTENTS

CITATION FORMAT

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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

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.

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.

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.

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.

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.

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

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (NA);
    b. Determination of Prevention of Significant Deterioration (NA); and
    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The following emissions unit is subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C.

ID	Emission Unit Description
006	Compressor Engine No. 1806 consisting of a 7200 bhp gas turbine

NSPS GENERAL PROVISIONS

In addition to the specific conditions of the permit and NSPS Subpart GG, the emissions unit is subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 60, SUBPART GG - STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

Each gas turbine shall comply with all applicable requirements of 40 CFR 60, Subpart GG adopted by reference in Rule 62-204.800(7)(b), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference. 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 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.

Section 60.330 Applicability and Designation of Affected Facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour), based on the lower heating value of the fuel fired.

Section 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

Section 60.332 Standard for Nitrogen Oxides.

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

(2) 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:

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

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≤0.015	0
0.015<N≤0.1	0.04(N)
0.1<N≤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: When firing natural gas, the "F" value shall be assumed to be "0".

{Permitting Note: The "Y" value when firing natural gas as provided by the manufacturer is approximately "11.4". The equivalent NOx emission standard is 190 ppmvd at 15% oxygen. The emissions standards in Section 3 of the permit are much more stringent than this requirement.}

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 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)(2) of this section.

Section 60.333 Standard for Sulfur Dioxide.

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

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

Section 60.334 Monitoring of Operations.

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

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

{Permitting Note: Excess NOx emissions reporting requirements do not apply. The gas turbine uses "dry" lean premix combustors and not wet injection to control NOx emissions. As indicated above, the Subpart GG NOx standard is 190 ppmvd @ 15% oxygen. This is nearly eight times the NOx standard specified in the permit and would be nearly impossible for this lean premix combustion turbine to exceed. As stated in the preamble to the July 2004 amendments, the rule changes do not impose any additional monitoring requirements for existing units.}

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332).

{Permitting Note: Because the nitrogen content of pipeline natural is negligible, the permittee does not claim an allowance for fuel bound nitrogen and will use "0" for the F-value when calculating the NOx standard in §60.332. The permit prohibits the permittee from claiming the allowance for fuel nitrogen. Therefore, no fuel nitrogen monitoring is required. The fuel monitoring provisions were revised pursuant to the final July 2004 amendments to Subpart GG.}

(3) May elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(v), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring.

§60.331(v) states, "*Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value."

The permittee elects not to monitor the sulfur content of natural gas based on §60.334(h)(3)(i), which states that, "The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less." The current tariff sheet specifies that natural gas delivered by the pipeline system shall contain not more than 10 grains of total sulfur per 100 cubic feet of gas. Therefore, the pipeline natural gas meets the above definition.

{Permitting Note: The permit requires the gas turbine to fire only pipeline natural gas with a maximum sulfur content of 10 grains of sulfur per 100 cubic feet of gas. Therefore, no fuel sulfur monitoring is required. The fuel monitoring provisions were revised pursuant to the final July 2004 amendments to Subpart GG.}

Section 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 Section 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 Section 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 Sections 60.332 and 60.333(a) as follows:

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

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

where:

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

Department Requirement: NOx emissions shall be corrected to ISO ambient atmospheric conditions for each required emissions performance test and compared to the NOx standard specified in 40 CFR 60.332.

(2) The monitoring device of Section 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Section 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 initial NOx performance tests shall be conducted at approximately four evenly spaced points between the minimum normal operating load and 100% of peak load.

{Permitting Note: The dry low-NOx controls are only effective above a minimum load, which will be identified during initial testing.}

(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.

Department Requirement: The span value shall be no greater than 75 ppm of nitrogen oxides due to the low NOx emission levels of the gas turbine.

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

(e) To meet the requirements of Section 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

{Permitting Note: The permit prohibits the permittee from claiming the allowance for fuel nitrogen. The permit also requires the gas turbine to fire only pipeline natural gas with a maximum sulfur content of 10 grains of sulfur per 100 cubic feet of gas. Therefore, no fuel nitrogen or fuel sulfur monitoring is required. The fuel monitoring provisions were revised pursuant to the final July 2004 amendments to Subpart GG.}

STANDARD CONDITIONS

{Permitting Note: Unless otherwise specified in the permit, 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 Allowed: 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. [Rule 62-210.700(1), F.A.C.]

4. 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.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

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

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. 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.]

12. 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.]

13. 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.]

14. 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 determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-210.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Gas Transmission Company
1400 Smith Street
Houston, TX 77002

Draft Air Permit No. 0950190-006-AC
Compressor Station 18, Engine 1806
Revised Air Construction Permit
Orange County, Florida

PROJECT DESCRIPTION

The applicant proposes several revisions to the original air construction permit for Engine 1806. As installed, the gas turbine fires slightly more natural gas to produce the required power output. The applicant requests approximately an 8% increase in the maximum heat input rate. Also, Engine 1806 is a light-industrial gas turbine with a power output of approximately 7200 bhp. It is common practice within the gas pipeline industry to replace the gas generator for maintenance and repair with a functionally equivalent component. The replaced gas generator is then shipped to a regional facility for maintenance and placed back into a pool of similar components. The applicant requests specific notification and testing requirements for conducting such functionally equivalent component replacements. Finally, EPA recently amended the federal monitoring requirements for fuel nitrogen and fuel sulfur in Subpart GG of 40 CFR for gas turbines. The applicant requests a permit revision to be consistent with the July 2004 amendments for fuel monitoring.

The requested changes are reasonable and not expected to result in increased emissions. The equivalent maximum emission rates for CO, NO_X, and VOC were not changed based on the initial test results. The equivalent maximum emission rates for SO_2 and PM were increased slightly because these rates were directly based on the maximum heat input rate. See the Technical Evaluation and Preliminary Determination for a detailed discussion of the revisions.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery F. Koerner — 10-19-04

Jeffery F. Koerner, P.E. — (Date)
Registration Number: 49441