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Florida Municipal Power Agency

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BUREAU OF AIR REGULATION

Susan Schumann
Environmental Licensing and Permitting

February 21, 2008

Mr. Tim Gray, Environmental Manager
Department of Environmental Protection
Southeast District Office
400 North Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Subject: Treasure Coast Energy Center Notification of Initial Startup

Dear Tim:

This letter is to serve as notification of initial startup at the Florida Municipal Power Agency's Treasure Coast Energy Center power plant project (the Project) as required by the Project's Conditions of Certification, Case No. PA 05-48A, Construction Permit No. PSD-FL-353, and 40 CFR 60.7(a)(3). First fire occurred at the Project on February 11, 2008. Therefore, this notification satisfies the requirement that notification of initial startup be postmarked within 15 days of the startup date.

If you have any questions regarding this notification, please contact me at (407) 355-7767 or via email at susan.schumann@fmpa.com.

Sincerely,

Susan Schumann

Susan Schumann
Florida Municipal Power Agency

cc: Mike Halpin, FDEP Program Administrator, Siting Office
Trina Vielhauer, FDEP Chief, Bureau of Air Regulation

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Memorandum

Florida Department of Environmental Protection

TO: Michael G. Cooke, Director DARM

TO: Trina L. Vielhauer, Chief BAR

THROUGH A.A. Linero, P.E., Program Administrator, South Permitting Section aaf

FROM: Cindy Mulkey CEM

DATE: May 17, 2006

SUBJECT: FMPA Treasure Coast Energy Center 300 MW Combined Cycle Project
DEP File No. 1110121-001-AC (PSD-FL-353)

Attached is the Final PSD Permit for the FMPA Treasure Coast Energy Center. The project consists of one gas-fired combined cycle power plant which includes one 170 W combustion turbine generator, one heat recovery steam generator, a 130 MW steam turbine generator, a fuel oil storage tank, cooling tower, and auxiliary equipment. The site is located southwest of the city of Fort Pierce in St Lucie County. The nearest PSD Class I Area, Everglades National Park is 180 km to the southwest. The Chassahowitzka Class I area is 260 km to the Northwest of the site.

Nitrogen Oxides (NO_X) emissions will be controlled by SCR to 2.0 parts per million at 15 percent oxygen (ppmvd @15%O_2) on a 24-hr basis when firing natural gas. This is the lowest value yet in the Southeast. Emissions when firing fuel oil will be 8 ppmvd@15% O_2.

Carbon monoxide (CO) will be controlled to 4.1 and 8.0 ppmvd @15% O_2 when burning natural gas and fuel oil respectively with allowances for the duct burners when used. Although the 24-hr limit of 8.0 ppm reflects the possibility of operation in high power modes for an entire day, the 12-month limit of 6 ppm more accurately reflects the long term mix of modes.

VOC, SO_2, sulfuric acid mist and particulate matter emissions will be inherently low due to the use of inherently clean fuels. FMPA has committed to use ultra low sulfur (0.0015% S) fuel oil for backup purposes 500 hours per year. We have set an ammonia limit of 5 ppmvd @15% O_2. This not only minimizes particulate formation, but also reduces nitrogen deposition.

We concluded that the project will not cause or contribute to violations of the ambient air quality standards or the Class I increments and that there will be no adverse impacts on air quality related values (AQRVs) such as visibility.

No comments were received from the public during the 30-day public comment period. Written comments received from FMPA are discussed and addressed in the attached Final Determination to Issue a PSD Permit.

The Siting Board granted certification on May 16. I recommend your approval of the final PSD Permit as soon we receive our copy of the signed Certification Order.

AAL/aal

Attachments

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Roger Fontes, General Manager and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819
______________________/

DEP File No1110121-001-AC
Final Permit No. PSD-FL-353
FMPA Treasure Coast Energy Center
One nominal 300 MW Combined Cycle Unit
St. Lucie County

Enclosed is the Final Permit Number PSD-FL-353 (1110121-001-AC) to construct/install one nominal 300 MW combined cycle unit and auxiliary equipment at the FMPA Treasure Coast Energy Center in St. Lucie County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronic mail before the close of business on 5/30/06 to the person(s) listed:

Roger Fontes, FMPA*
Susan Schumann, FMPA
Mayor, Fort Pierce
Chair, St. Lucie County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Hamilton Oven, DEP Siting Office
Darrel Graziani, DEP SED
Stanley Armbruster, P.E., B & V

Clerk Stamp

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

(Clerk) 5/30/06
(Date)

FINAL DETERMINATION

FLORIDA MUNICIPAL POWER AGENCY
TREASURE COAST ENERGY CENTER
DEP FILE NO. 1110121-001-AC (PSD-FL-353)

On October 28, 2005 the Florida Department of Environmental Protection (Department) distributed an "Intent to Issue Air Construction Permit" to construct a nominal 300 megawatt combined cycle combustion turbine project at the proposed Treasure Coast Energy Center near Fort Pierce, St. Lucie County. The project includes one 170 MW combustion turbine generator, one heat recovery steam generator, a 130 MW steam turbine generator, a fuel oil storage tank, a mechanical draft cooling tower, and auxiliary equipment.

The package included the Department's Draft Air Construction Permit, the "Intent to Issue Air Construction Permit," the "Technical Evaluation and Preliminary Determination," and the "Public Notice of Intent to Issue Air Construction Permit." The Department sent copies of the package to various persons, agencies, and municipalities. Florida Municipal Power Agency (FMPA) published the Public Notice in The Fort Pierce Tribune on November 14 and provided to the Department the required proof of publication.

On November 4, 2005 FMPA requested an extension of time, to January 3, 2006, to file a petition for an administrative hearing. On December 2 the Department granted the extension. On January 3 FMPA requested a further extension of time to January 17 which was also granted by the Department. No requests for administrative hearings were received on the Notice of Intent to Issue.

An evidentiary hearing was held on February 8, 2006 and a Recommended Order was entered on March 30, 2006 to:

"Grant full and final certification to Florida Municipal Power Agency, under Section 403, Part II, Florida Statutes, for the location, construction, and operation Treasure Coast Energy Center, representing a 300 MW combined cycle unit, as described in the Site Certification Application and the evidence presented at the certification hearing, and subject to the Conditions of Certification." Final Certification was approved on May 16, 2006.

The Department is required to take final action on the PSD Permit Application and the draft permit within 30 days following Final Certification by the Siting Board. This Final Determination recapitulates all comments and changes since the distribution of the Notice of Intent to Issue PSD Permit on October 28, 2005.

Written comments were received during the 30-day public comment period from FMPA requesting clarifications, corrections, and modifications to several items and conditions of the draft permit. The Department has also recognized the need for minor corrections to certain conditions. No comments were received from other agencies or the public regarding the Draft Air Construction Permit. FMPA submitted additional comments after the 30 day comment period regarding the Technical Evaluation and Preliminary Determination.

FMPA's comments are addressed, and corrections have been made as necessary, in this Final Permit. The changes requested by FMPA and our responses are listed below, as well as corrections initiated by the Department. A copy of the revised Draft Permit is attached.

The comments from FMPA include their proposed revisions (*italics*) followed by the Department's response.

Any additions to permit conditions are underlined and deletions are indicated by double strike-through notation.

1. *FMPA states: Expiration of permit should be extended to July 31, 2009 to allow for flexibility in construction schedule.*

   The requested expiration date of the permit is consistent with other similar projects. The Department will extend the expiration date to July 31, 2009.

2. *FMPA requested a change of the Authorized Representative to Thomas W. Richards, Director of Electric and Gas Systems.*

   Since the receipt of these written comments, FMPA has cancelled the request to change the Authorized Representative. However, the Authorized Representative currently listed on the Draft Permit is incorrect and will be changed to reflect the original application: Roger Fontes, General Manager and CEO.

3. *FMPA requests a change in the language under Section I, Regulatory Classification, NSPS regarding Subpart KKKK applicability. FMPA states that Subpart KKKK applicability will be dependent upon the final rule wording; applicability may change from original proposed language.*

   The requested change in the Section I, Regulatory Classification applicability language will have no impact on final applicability of the Rule to this unit. The Department will make the change to Section I, Regulatory Classification, NSPS as follows:

   When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the facility ~~will~~ may be subject to Subpart KKKK, and may no longer be subject to subparts GG and Da.

4. *FMPA requests correction of the date of the proposed NSPS Subpart KKKK, and a change in the language of Section III,A, Condition 2(d) regarding Subpart KKKK applicability similar to the language in Section I above.*

   The Department will make the date correction and language change to Section III, Condition 2(d), consistent with the above request (No. 3) as follows:

   (d) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions were published February 18, ~~2004~~ 2005 as a proposed new NSPS standard. The final rule ~~will~~ may be applicable to Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

5. *FMPA requests revision of maximum heat input rate in Section III, A, Condition 4 from 565 MMBtu to 565.3 MMBtu, consistent with page 16 of the TCEC PSD application.*

   The Department will make the requested change. Section III, Condition 4 will be changed as follows:

   4. HRSG: The permittee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of ~~565~~ 565.3 MMBtu per hour (HHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. [Application; Design]

6. *FMPA requests correction of Section III, A, Condition 7 reference of 40 CFR 60.130 to 40 CFR 68.130.*

   The Department agrees that 40 CFR 60.130 refers to the NSPS for Brass and Bronze Production Plants and acknowledges this as a typing error. The correction to Section III, Condition 7 will be made to reflect the proper reference to the Chemical Accident Prevention provisions as follows:

Ammonia Storage: In accordance with 40 CFR 6~~0~~8.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

7. *FMPA states: The combustion turbine has been purchased, and the final performance runs indicate the fuel oil heat input will be slightly higher, revised from 1,967 MMBtu, to 1,986 MMBtu per hour. FMPA requests that the Department change Section III, A, Condition 8 to reflect the maximum heat rate of the purchased gas turbine.*

FMPA is not requesting an increase in mass emissions rates with this change in heat input. Section III, A, Condition 8 will be changed as follows:

8. Permitted Capacity – Gas Turbine: The maximum heat input rate to the gas turbine is 1,787 MMBtu per hour when firing natural gas and ~~1,967~~ 1,986 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

8. *FMPA requests revision of maximum heat input rate in Section III, A, Condition 9 from 560 MMBtu to 565.3 MMBtu, consistent with page 16 of the TCEC PSD application.*

The Department will change Section III, A, Condition 9 for consistency with Condition 4 of the permit (see No. 5 above) as follows:

9. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for the HRSG is ~~560~~ 565.3 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

9. *FMPA states: Duct firing will not be limited to only natural gas firing of the combustion turbine. This is consistent with page TE-5 of the Technical Evaluation document, where FDEP recognizes that FMPA "requests unlimited use of duct burning while firing either gas or oil in the combustion turbine." FMPA requests a change in Section III, A, Condition 12.d to reflect this ability.*

The Department agrees with FMPA's request. Unlimited use of duct firing was requested by FMPA in the application and acknowledged in the Technical Evaluation. Air quality modeling was conducted based on a worst case selection from a number of operating scenarios (including the use of duct burners while firing oil). However, the emission standards for carbon monoxide and nitrogen oxides of Condition 13 do not include this method of operation. An additional method of operation (combustion turbine and duct burner) while firing oil will be added to the emissions standards in the table.

It has also been brought to the Department's attention that some of the mass emission rates (lb/hr) listed in the Condition 13, Emission Standards table do not precisely coincide with the mass emission rates submitted by the applicant for the given concentration. This is the result of an independent calculation estimating the mass emission rates using an f-factor and the given heat input rate for each concentration. Where they occur, the differences are less than $\pm$ 2 % and in most cases less than $\pm$ 1%. The Department will change the values in the table to reflect those listed in the application. Modeling was based on the rates submitted in the application and the changes will have no impact on any determinations made by the Department.

The following specific changes to Section III, A, Conditions 12.d. and 13 will be made:

12.d. *Duct Firing*: ~~When firing natural gas, the~~ The HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

13. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS ~~Block~~ Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.~~1~~8	8.0, 24-hr block
		CT & Duct Burner (DB)	8.0	47.3	
	Gas	CT, Normal	4.1	16.~~4~~2	
		CT & (DB)	7.6	39.~~7~~1	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	6~~1~~2.0	8.0, 24-hr block
		CT & DB	8.0	78.0	
	Gas	CT, Normal	2.0	13.~~2~~1	2.0, 24-hr block
		CT & DB	2.0	1~~7~~6.~~1~~9	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

10. *Referring to Section III, A, Condition 13, FMPA states that they understand "calendar 12-month-annual-average" will be utilized as CEMS block average.*

FMPA refers to the "12-month" average for carbon monoxide included in Condition No. 13. The Department intends this to be a 12-month "rolling" average. The word "Block" will be removed from the last column header of the table and added to the appropriate averaging periods in the Section III, A, Condition 13 table (see table in comment 9 above). For clarification, the following language will be inserted into Condition 26 of the same section, as Condition 26.d. The existing Conditions 26.d. and 26.e. will become 26.e. and 26.f.

26.d. 12-month Rolling Average: Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

11. *FMPA requests revision of language from "shall" to "may", in Section III, A, Condition 13.b, consistent with 13.a.*

This condition establishes requirements for continuous compliance with the NO_X standards. FMPA's request would allow more flexibility during the required testing and is consistent with continuous compliance with the CO standards. The Department will change Condition 13.b. as shown below. However, this does not preclude the use of *any* available data as credible evidence of compliance or non-compliance.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments ~~shall~~ may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

12. *FMPA requests clarification of language to reflect proper training for maintenance procedure in Section III, A, Condition 14. FMPA further states that due to the complexity of the units, operators are not trained to "maintain" the units, but they will be trained to identify, troubleshoot, and coordinate maintenance items.*

The Department agrees to make the following change to Section III, A, Condition 14:

14. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ~~maintain~~ ensure maintenance of the gas turbine, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions.

13. *FMPA requests clarification of language by adding "for good cause" to Section III, A, Condition 22.*

FMPA refers to the following statement included in Condition 22: "The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc."

The Department has the authority, under Rule 62-297.310(7)(b), to request a special compliance test when, after investigation, there is good reason to believe that any applicable emission standard contained in a permit is being violated. Major replacement or repair of air pollution control equipment may certainly constitute good reason for a special compliance test to ensure the new or repaired equipment is functioning properly and is capable of meeting the required standards. The Department has no objections to FMPA's request and will change Condition 22 as follows:

22. The Department may require, for good reason, the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a) and (b), F.A.C.]

14. *FMPA suggests removal of the following sentence from Section III, A, Condition 24: "The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above." FMPA states that Condition 13 specifically indicates that short-term limits are based on stack tests.*

Compliance with the short-term CO and NO_X standards must be demonstrated annually by conducting stack tests for each pollutant. The statement from Section III, A, Condition 24 will be removed because the Department agrees this language is superfluous. With or without this language, the Department would have the ability to present any evidence in an enforcement action, including CEMS data, to support an allegation of an emission limitation violation.

24. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA.

Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. ~~The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short-term CO and NOX limits for each method of operation given in Condition 12 above~~. [Rule 62-212.400 (BACT), F.A.C.]

15. *FMPA requests clarification of Section III, A, Condition 30.b. to reflect fuel sampling procedures to include permittee or vendor.*

The Department will accept vendor certification of fuel oil sulfur content. The Department will change Section III, A, Condition 30.b. as follows:

b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by sampling and analysis of the fuel by the permittee or vendor ~~taking a sample, analyzing the sample~~ for ~~fuel~~ sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each ~~subsequent~~ fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or from an analysis conducted by the permittee, in accordance with the above methods. At the request of the Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

16. *FMPA requests clarification of Section III, C, Condition 2 to reflect commercial operation.*

The Department agrees with the requested change and will change Section III, C, Condition 2 as follows:

2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

17. *FMPA requests that the unit description be updated to accurately describe the safe shutdown generator(Unit 004) in Section III, D of the permit. FMPA states that the Engineer, Procure, Construct (EPC) final specification includes a 750kw/1000hp generator.*

The original application received by FMPA estimated the size of the safe shutdown generator to be approximately 765 hp and, consequently this is included in the Emission Unit Description for this unit. Since the submittal of these comments, FMPA has provided to the Department additional modeling information demonstrating no significant impacts when adjustments are made for an additional increase in engine size to 1525 hp. The small annual emission increases associated with the larger safe shutdown generator are offset by the facility decrease in emission due to the removal of the auxiliary boiler which was originally included in the application. Therefore, there are no increases in the potential to emit of the facility, as compared to the potential to emit values included in the original application.

The unit description in Section I, and Section IIII D for the safe shutdown generator (Unit 004) will be modified as follows:

ID	Emission Unit Description
004	One safe shutdown generator (approximately ~~765~~ 1525 hp) with associated 1000 gallon fuel oil storage tank.

18. The Department has become aware of a proposed NSPS for certain combustion engines, 40 CFR Parts 60, 85, 89, et al. (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule). The safe shutdown generator and the diesel fire pump may be subject to this rule at the time the rule becomes final.

The following NSPS applicability statement will be added to Section III, D. Safe Shutdown Generator (EU 004):

NSPS APPLICABILITY

NSPS Subpart IIII Applicability: The emergency generator is a Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and may be subject to 40 CFR 60, Subpart IIII at the time the proposed rule becomes final.

The emergency generator shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations.

[40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register / Vol. 70, No. 131 / July 11, 2005. Pages 39869 – 39904].

The following NSPS applicability statement will be added to Section III, E. Diesel Fire Pump (EU 005):

NSPS APPLICABILITY

NSPS Subpart IIII Applicability: This fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and may be subject to 40 CFR 60, Subpart IIII at the time the proposed rule becomes final.

The fire pump engine shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emission unit and its operations.

[40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register / Vol. 70, No. 131 / July 11, 2005. Pages 39869 – 39904].

19. Appendices GG and Da of the draft permit do not include amendments to Subpart GG affective July 8, 2004, amendments to Subpart Da affective February 7, 2006. Appendices GG, and Da of the permit have been updated to reflect the latest amendments to the subparts.

20. FMPA submitted comments on the Technical Evaluation and Preliminary Determination (TEPD) to the Siting Coordination Office following the 30-day comment period. FMPA requested the following changes be made to Tables 21 and 23 depicting Maximum Projected Air Quality Impacts.

Table 21. Maximum Projected Air Quality Impacts from Treasure Coast Energy Center Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	Baseline Concentrations (ug/m3)	Ambient Air Standards (ug/m3)	Significant Impact?
SO_2	Annual	0.1	1	~3	60	NO
	24-Hour	1	5	~5	260	NO
	3-Hour	3	25	~10	1300	NO
PM_{10}	Annual	0.3 ~~0.2~~	1	~17	50	NO
	24-Hour	4.8 ~~4.2~~	5	~65	150	NO
CO	8-Hour	17	500	~2300	10,000	NO
	1-Hour	124 ~~127~~	2000	~5750	40,000	NO
NO_2	Annual	0.4 ~~0.1~~	1	~17	100	NO

Table 23. Maximum Air Quality Impacts vs. the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4.8	10	~65	NO
NO_2	Annual	0.4 ~~0.1~~	14	~17	NO
SO_2	24-hour	1	13	~5	NO
CO	8-hour	17	575	~2300	NO

The above changes do not impact Department findings nor do they affect any specific requirements of the permit. FMPA's comments are noted and this document will become part of the facility's official files. However, there is no final TEPD document.

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

PERMITTEE:

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative:
Roger Fontes, General Manager and CEO

Treasure Coast Energy Center	
DEP File No.	1110121-001-AC
Final Permit No.	PSD-FL-353
SIC No.	4911
Expires:	July 31, 2009

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 300 MW gas-fired combined cycle electrical power plant. The project will include one 170 MW combustion turbine generator, one heat recovery steam generator, a 130 MW steam turbine generator, a fuel oil storage tank, a mechanical draft cooling tower, and auxiliary equipment. The project will be located southwest of the city of Fort Pierce, East of Highway 95 in St. Lucie County.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Michael G. Cooke, Director
Division of Air Resources Management
Date: 5/19/06

FACILITY DESCRIPTION

The proposed FMPA facility is a combined cycle power plant. The project is to install one combined cycle unit which will consist of one gas turbine (nominal 170 MW) and one heat recovery steam generator with supplementary duct firing, a steam turbine-electrical generator (nominal 130 MW), a mechanical draft cooling tower, and one 990,000 gallon fuel oil storage tank. Ancillary equipment includes a diesel engine driven fire pump with associated 500 gallon fuel oil tank, and a safe shutdown generator.

EMISSIONS UNITS

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

EU ID NO.	EMISSION UNIT DESCRIPTION
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).
002	One distillate fuel oil storage tank for Unit 1 combustion turbine (approximately 1 million gallons).
003	One 8-cell mechanical draft cooling tower.
004	One safe shutdown generator (approximately 1,525 hp) with associated 1000 gallon fuel oil storage tank.
005	One diesel engine fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank.

REGULATORY CLASSIFICATION

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

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

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the facility may be subject to Subpart KKKK, and may no longer be subject to subparts GG and Da. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a "Major Source" of HAPs and Unit 1 is not subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Southeast District, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

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 received on April 14, 2005
- Department's Determination of Sufficiency – Found Insufficient June, 6 2005
- FMPA Sufficiency responses dated July 28, 2005
- Department's Second Determination of Sufficiency – Found Sufficient August 29, 2005
- Department's Intent to Issue and Public Notice Package dated October 28, 2005
- Final Certification by the Power Plant Siting Board on May 16, 2006; and
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

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

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. 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.]

5. 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. [Chapters 62-210 and 62-212, F.A.C.]

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

7. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Unit 1 Combined Cycle Gas Turbine (EU 001)

This section of the permit addresses the following emissions unit.

E.U. ID	Emission Unit Description
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards for Subpart Da, Subpart GG, and Subpart KKKK (as proposed). Some separate reporting and monitoring may be required by the individual subparts.

   (a) **Subpart A, General Provisions**, 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
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Subpart Da, Standards of Performance for Electric Utility Steam Generating Units** These provisions include standards for duct burners.

   (c) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (d) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions were published February 18, 2005 as a proposed new NSPS standard. The final rule may be applicable to Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

EQUIPMENT

3. Gas Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 170 MW. The gas turbine will be equipped with DLN combustors, and an inlet air filtration system with evaporative coolers. The unit shall include the Speedtronic™ Mark VI automated gas turbine control system, and will have dual-fuel capability. [Application; Design]

4. HRSG: The permittee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 565.3 MMBtu per hour (HHV).

The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. [Application; Design]

CONTROL TECHNOLOGY

5. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

6. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for the gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

7. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

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

PERFORMANCE RESTRICTIONS

8. Permitted Capacity – Gas Turbine: The maximum heat input rate to the gas turbine is 1,787 MMBtu per hour when firing natural gas and 1,986 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

9. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for the HRSG is 565.3 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

10. Hours of Operation: The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

11. Authorized Fuels: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. The

gas turbine shall fire no more than 500 hours of fuel oil, regardless of mode, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

12. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

    a. *Combined Cycle Operation*: The gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

    b. *Pseudo Simple Cycle Operation*: The gas turbine/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

    c. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."

    d. *Duct Firing*: The HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

    [Application; Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.]

EMISSIONS STANDARDS

13. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-h block
		CT & Duct Burner (DB)	8.0	47.3	
	Gas	CT, Normal	4.1	16.2	
		CT & (DB)	7.6	39.1	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	62.0	8.0, 24-hr block
		CT & DB	8.0	78.0	
	Gas	CT, Normal	2.0	13.1	2.0, 24-hr block
		CT & DB	2.0	16.9	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, established in Condition No. 11 of this section, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be determined by the requirements in Condition No. 30 of this section. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, established in Condition No. 11 this section, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 30 of this section.

e. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

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

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

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

15. Definitions

a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
[Rule 62-210.200(245), F.A.C.]

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
[Rule 62-210.200(230), F.A.C.]

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
[Rule 62-210.200(159), F.A.C.]

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

17. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

18. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine/HRSG system, excess emissions from the gas turbine/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

       {Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue}

    b. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

    c. *Shutdown:* For shutdown of the combined cycle operation, excess emissions from the gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

    d. *Fuel Switching:* Excess emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbine/HRSG system including the pollution control equipment. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Determinations: The gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. The unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. The Department may, for good reason, require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a) and (b), F.A.C. and 40 CFR 60.8]

23. Annual Compliance Tests: During each federal fiscal year (October 1st, to September 30th), the gas turbine shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NOX emissions standards based on data collected by the certified CEMS. Within 45 days of conducting

any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

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

    c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

    a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages:* Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months

e. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 18 and 20 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

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

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

RECORDS AND REPORTS

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

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

    a. *Natural Gas:* Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *Fuel Oil:* Compliance with the distillate fuel oil sulfur limit shall be demonstrated by sampling and analysis of the fuel by the permittee or vendor for sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or from an analysis conducted by the permittee, in accordance with the above methods. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

   a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

   b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

   c. *NSPS Semi-Annual Reports*: For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority. This also includes reporting any periods of excess emissions as applicable and defined by NSPS Subpart KKKK when the rule is finalized.

{Note: If there are no periods of excess emissions as defined in NSPS Subparts GG, Da, or KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. Fuel Oil Storage Tank (EU 002)

ID	Emission Unit Description
002	One distillate fuel oil storage tank for Unit 1 combustion turbine (approximately 1 million gallons).

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 5.2 kPa and greater than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the monitoring requirements. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. The fuel oil storage tank (EU 002) has a capacity greater than 151 cubic meters and the vapor pressure of the ultra low sulfur fuel oil is less than 3.5 kPa, therefore NSPS Kb, including the monitoring requirements, does not apply to this unit.
[40 CFR 60.110b(a) and (b), and 60.116b(c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one 990,000 gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 1 gas turbine. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year).
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for use in the Annual Operating Report.
[Rule 62-204.800(7)(b)16, F.A.C]

C. Cooling Tower (EU 003)

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

ID	Emission Unit Description
003	One 8-cell mechanical draft cooling tower.

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one 8-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 111,130 gpm; a design air flow rate of 1,000,000 acfm per cell; drift eliminators; a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 10 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}.

D. Safe Shutdown Generator (EU 004)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
004	One safe shutdown generator (approximately 1,525 hp) with associated 1000 gallon fuel oil storage tank.

NESHAP Applicability

NESHAP Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

NSPS Applicability

NSPS Subpart IIII Applicability: The emergency generator is a Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and may be subject to 40 CFR 60, Subpart IIII at the time the proposed rule becomes final.

The emergency generator shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations.

[40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register / Vol. 70, No. 131 / July 11, 2005. Pages 39869 – 39904].

Equipment Specifications

1. Safe Shutdown Generator: The permittee is authorized to install, operate, and maintain one safe shutdown generator. The safe shutdown generator may operate when the transmission connection is lost and the plant shuts down, and during occasional testing to ensure operability. The safe shutdown generator will fire ULS fuel oil. [Application; Design]

Emissions and Performance Requirements

2. Hours of Operation: The safe shutdown generator may operate 200 hours per year.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

{Permitting Note: Emissions from the safe shutdown generator are included in the potential to emit for the project.}

E. Diesel Fire Pump (EU 005)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
005	One diesel engine fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank.

NESHAP APPLICABILITY

NESHAP Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

NSPS APPLICABILITY

NSPS Subpart IIII Applicability: This fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and may be subject to 40 CFR 60, Subpart IIII at the time the proposed rule becomes final.

The fire pump engine shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emission unit and its operations.

[40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register / Vol. 70, No. 131 / July 11, 2005. Pages 39869 – 39904].

EQUIPMENT SPECIFICATIONS

1. Fire Pump: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank. The diesel engine fire pump will fire ULS fuel oil. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

Hours of Operation: The fire pump may operate 200 hours per year.
[Applicant Request; Rule 62-210.200 (PTE), F.A.C.

{Permitting Note: The fire pump is considered emergency equipment, therefore exempt from permitting, however its emissions are included in the potential to emit for the project.}

CONTENTS

Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements for Duct Burners
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix SC	Standard Conditions

NSPS Subpart A, Identification of General Provisions

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-h block
		CT & Duct Burner (DB)	8.0	47.3	
	Gas	CT, Normal	4.1	16.2	
		CT & (DB)	7.6	39.1	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	62.0	8.0, 24-hr block
		CT & DB	8.0	78.0	
	Gas	CT, Normal	2.0	13.1	2.0, 24-hr block
		CT & DB	2.0	16.9	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, established in Condition No. 11 of this section, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be determined by the requirements in Condition No. 30 of this section. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, established in Condition No. 11 this section, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 30 of this section.

e. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

Trina L. Vielhauer, Chief
Bureau of Air Regulation

5/18/06
Date

Approved By:

Michael G. Cooke, Director
Division of Air Resources Management

5/19/06
Date

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 1 gas turbine/HRSG system, which are regulated as Emissions Unit 001.

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49453, Sept. 16, 1998. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9876, Feb. 27, 2006]

§ 60.41Da 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.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–77 (incorporated by reference—see §60.17).

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)ϵ 1 (incorporated by reference, see §60.17).

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)ϵ 1 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels in any amount. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or dry FGD means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or ESP means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emergency condition means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or 40 CFR 51.18 and 40 CFR 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or IGCC means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835–87, 91, 97, or 03a (incorporated by reference, see §60.17).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under §60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

Potential electrical output capacity is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

Spare flue gas desulfurization system module means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

Wet flue gas desulfurization technology or wet FGD means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

[44 FR 33613, June 11, 1979, as amended at 48 FR 3737, Jan. 27, 1983; 63 FR 49453, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 66 FR 18551, Apr. 10, 2001; 70 FR 28652, May 18, 2005. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9876, Feb. 27, 2006]

§ 60.42Da Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

[44 FR 33613, June 11, 1979. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9877, Feb. 27, 2006]

§ 60.43Da Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under §60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery unit, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO2 commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.45Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_s=(340x+520y)/100$ and

%Ps=10

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

Es=(340x+520 y)/100 and

%Ps=(10x+30 y)/100

where:

Es is the prorated sulfur dioxide emission limit (ng/J heat input),

%Ps is the percentage of potential sulfur dioxide emission allowed.

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

(i) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that is located in a noncontinental area, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9877, Feb. 27, 2006]

§ 60.44Da Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as NO2) in excess of the following emission limits, based on a 30-day rolling average, except as provided under §60.48Da(j)(1):

(1) NOx emission limits.

Fuel type	Emission limit for heat input: ng/J	Emission limit for heat input: (lb/ million Btu)
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(\1\ )	(\1\ )
Any fuel containing more than 25%, by weight,	340	0.80

lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace\2\...........		
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit\2\......................		
Subbituminous coal...........................	210	0.50
Bituminous coal..............................	260	0.60
Anthracite coal..............................	260	0.60
All other fuels..............................	260	0.60

\1\ Exempt from NOX standards and NOX monitoring requirements.
\2\ Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) *NOx reduction requirement.*

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels..	25
Liquid fuels...	30
Solid fuels..	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n=[86\,w+130x+210\,y+260\,z+340\,v]/100$$

where:

En is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(1) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator of an IGCC subject to the provisions of this subpart that burns liquid fuel as a supplemental fuel and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided for in paragraphs (f)(2) and (3) of this section.

(2) When burning liquid fuel exclusively or in combination with synthetic gas derived from coal such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49453, Sept. 16, 1998; 66 FR 18551, Apr. 10, 2001; 66 FR 42610, Aug. 14, 2001. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

§ 60.45Da Standard for mercury.

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in §60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 21 × 10− 6 pound per megawatt hour (lb/MWh) or 0.021 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0026 nanograms per joule (ng/J).

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If you utilize wet FGD technology to limit SO2 emissions from your steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 42 × 10− 6 lb/MWh or 0.042 lb/GWh on an output basis. The SI equivalent is 0.0053 ng/J.

(ii) If you utilize dry FGD technology to limit SO2 emissions from your steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 78 × 10− 6 lb/MWh or 0.078 lb/GWh on an output basis. The SI equivalent is 0.0098 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 145 × 10− 6 lb/MWh or 0.145 lb/GWh on an output basis. The SI equivalent is 0.0183 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 1.4 × 10−6 lb/MWh or 0.0014 lb/GWh on an output basis. The SI equivalent is 0.00018 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (i.e., bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in British thermal units, Btu) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i \left(HH_i\right)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

ELb = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged under the blending provision.

ELi = Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh.

HHi = Electricity output from affected source during the production period related to use of the corresponding subcategory i (coal rank) that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of electricity output (in MWh) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of 20 × 10−6 lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in §60.50Da(g).

[70 FR 28653, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO2 emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO2 emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NOX emission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I)	SO2	6,000-10,000
Fluidized bed combustion (atmospheric)	SO2	400-3,000
Fluidized bed combustion (pressurized)	SO2	400-1,200

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Coal liquification..........................        NOX       750-10,000
                                                              ---------------
    Total allowable for all technologies.....  .........          15,000
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[44 FR 33613, June 11, 1979. Redesignated at 70 FR 28653, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.48Da Compliance provisions.

(a) Compliance with the particulate matter emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under §60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under §60.44Da(a) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The particulate matter emission standards under §60.42Da, the nitrogen oxides emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under §60.43Da for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under §60.43Da and the nitrogen oxides emission limitation under §60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2) only.

(2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

(i) Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to §60.44Da(d)(1) or (e)(1) shall calculate NO_X emissions by multiplying the average hourly NO_X output concentration, measured according to the provisions of §60.49Da(c), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(j) Compliance provisions for duct burners subject to §60.44Da(a)(1). To determine compliance with the emissions limits for NO_X required by §60.44a(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system specified under §60.49Da for measuring NO_X and oxygen and meet the requirements of §60.49a. Data from a CEMS certified (or recertified) according to the provisions of 40 CFR 75.20, meeting the QA and QC requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emission rate at the outlet from the steam generating unit shall constitute the NO_X emission rate from the duct burner of the combined cycle system.

(k) Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1). To determine compliance with the emission limitation for NO_X required by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_X shall be computed using Equation 1 of this section:

$$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h) \quad \text{(Eq. 1)}$$

Where:

E = emission rate of NO_X from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf)

Cte = average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = average hourly gross energy output from steam generating unit, J (Mwh)

h = average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

(ii) Method 7E of appendix A of this part shall be used to determine the NOX concentrations (Csg and Cte). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NOX emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOX shall be computed using Equation 2 of this section:

$E = (Csg \times Qsd) / Occ$ (Eq. 2)

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

Csg = average hourly concentration of NOX exiting the steam generating unit, ng/dscm (lb/dscf)

Qsg = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under §60.49Da for measuring NOX and oxygen shall be used to determine the average hourly NOX concentrations (Csg). The continuous flow monitoring system specified in §60.49Da(l) shall be used to determine the volumetric flow rate (Qsg) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (Occ), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NOX emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NOX shall be computed using Equation 3 of this section:

$E = (ERsg \times Hcc) / Occ$ (Eq. 3)

Where:

E = emission rate of NOX from the duct burner, ng/J (lb/Mwh) gross output

ERsg = average hourly emission rate of NOX exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) Compliance provisions for sources subject to §60.45Da. The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45a is determined on a 12-month rolling average basis.

(m) Compliance provisions for sources subject to §60.43Da(i)(1)(i) or (j)(1)(i). The owner or operator of an affected facility subject to §60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO2 emissions by multiplying the average hourly SO2 output concentration, measured according to the provisions of §60.49Da(b), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(n) Compliance provisions for sources subject to §60.42Da(c)(1). The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) Compliance provisions for sources subject to §60.42Da(c)(2) or (d). Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in §60.50Da to demonstrate compliance by the applicable date specified in §60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with §60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in §60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49454, Sept. 16, 1998; 66 FR 18552, Apr. 10, 2001; 66 FR 31178, June 11, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51a shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO2 concentration at the same location as the SO2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NOX concentration at the same location as the NOX monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O2 or CO2 concentration at the same location as the O2 or CO2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 shall be used to determine O2, SO2, and NOX concentrations, respectively.

(2) SO2 or NOX (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NOX standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in §60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990; 63 FR 49454, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 66 FR 18553, Apr. 10, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9880, Feb. 27, 2006]

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO2 and NOX. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.42Da as follows:

(1) The dry basis F factor (O2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ±14 °C (320 ±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O2 concentration. The O2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O2 traverse points. If the grab sampling procedure is used, the O2 concentration for the run shall be the arithmetic mean of the sample O2 concentrations at all traverse points.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO2 standards in §60.43Da as follows:

(1) The percent of potential SO2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

%Ps=[(100—%Rf) (100—%Rg)]/100

where:

%Ps=percent of potential SO2 emissions, percent.

%Rf=percent reduction from fuel pretreatment, percent.

%Rg=percent reduction by SO2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%Rf) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO2 reduction (%Rg) of any SO2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO2 control device and the average SO2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in §60.49Da (b) and (d) shall be used to determine the concentrations of SO2 and CO2 or O2.

(d) The owner or operator shall determine compliance with the NOX standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NOX.

(2) The continous monitoring system in §60.49Da (c) and (d) shall be used to determine the concentrations of NOX and CO2 or O2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The Fc factor (CO2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of §60.48(d)(1). The CO2 shall be determined in the same manner as the O2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

(g) For the purposes of determining compliance with the emission limits in §§60.45Da and 60.46Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (i.e., 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \quad \text{(Eq. 1)}$$

Where:

ERcogen = Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

Vgrid = Amount of energy sent to the grid over the same compliance period (MWh); and

Vprocess = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or

(h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\, C_h Q_h t_h \qquad \text{(Eq. 2)}$$

Where:

Eh = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24 × 10− 11 lb-scm/µg-scf

Ch = Hourly Hg concentration, wet basis, (µg/scm)

Qh = Hourly stack gas volumetric flow rate, (scfh)

th = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_h = K\, C_h Q_h t_h \left(1-B_{ws}\right) \qquad \text{(Eq. 3)}$$

Where:

Eh = Hg mass emissions for the hour, (lb)

K = Units conversion constant, 6.24 × 10− 11 lb-scm/µg-scf

Ch = Hourly Hg concentration, dry basis, (µg/dscm)

Qh = Hourly stack gas volumetric flow rate, (scfh)

th = Unit operating time, i.e., the fraction of the hour for which the unit operated

Bws = Stack gas moisture content, expressed as a decimal fraction (e.g., for 8 percent H2O, Bws = 0.08)

(C) Use Equation 4, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 4)}$$

Where:

M = Total Hg mass emissions for the month, (lb)

Eh = Hg mass emissions for hour "h", from Equation 2 or 3 of this section, (lb)

n = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below. For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 5)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh)

M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)

P = Total electrical output for the month, for the hours used to calculate M, (MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=i}^{12}(ER)_i n_i}{\sum_{i=i}^{12} n_i} \qquad \text{(Eq. 6)}$$

Where:

Eavg = Weighted 12-month rolling average Hg emission rate, (lb/MWh)

(ER)i = Monthly Hg emission rate, for month "i", (lb/MWh)

n = The number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps, Ch in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride (Hg° or HgCl2) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using HgCl2 standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 28653, 28655, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9881, Feb. 27, 2006]

Editorial Note: At 70 FR 51269, Aug. 30, 2005, the Environmental Protection Agency published a document in the Federal Register, attempting to amend §60.50Da. However, because of inaccurate amendatory language, this amendment could not be incorporated. For the convenience of the user, the language at 70 FR 51269 is set forth as follows:

f. Revising the existing reference in paragraph (e)(2) from "§60.48a(d)(1)" to "§60.48Da(d)(1)";

§ 60.51Da Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NOX only), emergency conditions (SO2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (si) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (Eo*) and the upper confidence limit for the mean inlet emission rate (Ei*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (Eo*) and the allowable emission rate (Estd) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 (appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO2 and/or NOX and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49454, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999. Redesignated and amended at 70 FR 28653, 28656, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005]

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da or §60.46Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

[70 FR 28656, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005]

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 (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emssion Standards for Hazardous Air Pollutants (X); and
    d. 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.

The Unit 1 gas turbine is regulated as Emissions Unit 001.

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 (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) (b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

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.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) Regenerative cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) Emergency gas turbine means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

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

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(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.

(k) Fire-fighting turbine means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) Turbines employed in oil/gas production or oil/gas transportation means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A Metropolitan Statistical Area or MSA as defined by the Department of Commerce.

(n) Offshore platform gas turbines means any stationary gas turbine located on a platform in an ocean.

(o) Garrison facility means any permanent military installation.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) Emergency fuel is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) Excess emissions means a specified averaging period over which either:

(1) The NOX emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) 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. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. 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 British thermal units (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.

(v) Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

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

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

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (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, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(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 ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak 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, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this seciton is optional. That is, the owner or operator may choose to apply a NOX allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NOX emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NOX percent by volume)
N [le] 0.015	0
0.015 < N[le] 0.1	0.04(N)
0.1 < N [le] 0.25	0.004+0.0067(N-0.1)
N > 0.25	0.005

Where:

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

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

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

(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.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) 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 and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NOX emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.333 Standard for sulfur dioxide.

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

(a) 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 sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOX emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOX emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOX and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NOX concentrations to 15 percent O2 by either converting the CO2 hourly averages to equivalent O2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O2, or by using the CO2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

   (1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NOX and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

      (i) On a ppm basis (for NOX) and a percent O2 basis for oxygen; or

      (ii) On a ppm at 15 percent O2 basis; or

      (iii) On a ppm basis (for NOX) and a percent CO2 basis (for a CO2 monitor that uses the procedures in Method 20 to correct the NOX data to 15 percent O2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NOX and diluent, the data acquisition and handling system must calculate and record the hourly NOX emissions in the units of the applicable NOX emission standard under §60.332(a), i.e., percent NOX by volume, dry basis, corrected to 15 percent O2 and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19.0 percent O2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

(iii) If the owner or operator has installed a NOX CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NOX emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NOX emission limit under §60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NOX emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NOX emissions may elect to use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NOX formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NOX) combustion mode.

(3) For any turbine that uses SCR to reduce NOX emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions

methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NOX emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

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

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(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). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator 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(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) 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; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NOX and diluent CEMS:

(A) (A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NOX concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NOX concentration" is the arithmetic average of the average NOX concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NOX concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOX concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) Ice fog. Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) Emergency fuel. Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004]

60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NOX and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NOX and diluent pursuant to

(A) [Reserved]

(B) (B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NOX concentration during the stratification test; or

(B) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NOXo) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

NOX=(NOXo)(Pr/Po)0.5 e19 (Ho–0.00633) (288°K/Ta)1.53

Where:

NOX = emission concentration of NOX at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,

NOXo = mean observed NOX concentration, ppm by volume, dry basis, at 15 percent O2,

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, and

Ta = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NOX emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NOX emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NOX with no additional post-combustion NOX control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NOX emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NOX CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NOX emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §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 prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section 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.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004]

STANDARD CONDITIONS

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 62-297.310(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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

FLORIDA MUNICIPAL POWER AGENCY,
Treasure Coast Energy Center,

Petitioner,

v. **OGC #05-2555**
DEP Permit 1110121-001-AC

DEPARTMENT OF ENVIRONMENTAL PROTECTION,

Respondent.

________________________________/

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection upon receipt of a request made by Petitioner, Florida Municipal Power Agency, to grant an extension of time to file a petition for an administrative hearing to allow time to provide certain information to the FDEP on several specific permit conditions for its facility in St. Lucie County, Florida. Because the request shows good cause for the extension of time,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until **January 25, 2006**, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 18th day of January, 2006, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JACK CHISOLM, Deputy General Counsel
3900 Commonwealth Boulevard. M.S. 35
Tallahassee, Florida 32399-3000
850-245-2242 facsimile 850-245-2302

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via _ U. S. Mail ✓ facsimile ✓ **only**, this 18th day of January, 2006, to:

Douglas S. Roberts, Esq.
Hopping Green & Sams, P.A.
P. O. Box 6526
Tallahassee, FL 32314

facsimile: 850-224-8551

STAN M. WARDEN, Assistant General Counsel
Florida Bar No. 144932
DEPT. OF ENVIRONMENTAL PROTECTION
3900 Commonwealth Boulevard, MS #35
Tallahassee, Florida 32399-3000
Telephone (850) 245-2242
Facsimile (850) 245-2302

with a courtesy copy to:

Trina L. Vielhauer
Chief
Bureau of Air Regulation

facsimile: 850-921-9533

RECEIVED

MAY 26 2006

BUREAU OF AIR REGULATION

STATE OF FLORIDA
SITING BOARD

IN RE: FLORIDA MUNICIPAL POWER AGENCY TREASURE COAST ENERGY CENTER POWER PLANT SITING APPLICATION NO. PA05-48.

DOAH CASE NO.: 05-1492EPP
OGC CASE NO.: 05-0744

CONSOLIDATED SITING BOARD FINAL ORDER ON LAND USE AND SITE CERTIFICATION

On March 30, 2006, an administrative law judge with the Division of Administrative Hearings ("DOAH") submitted two Recommended Orders in this administrative proceeding. The Recommended Orders indicate that copies were served upon counsel for the Applicant, Florida Municipal Power Agency ("FMPA"), the Department of Environmental Protection ("DEP"), St. Lucie County, and other designated agencies. Copies of the Recommended Orders are attached hereto as Exhibits A and B. The matter is now before the Governor and Cabinet, sitting as the "Siting Board," for final agency action under the Florida Electrical Power Plant Siting Act ("PPSA") embodied in §§ 403.501-403.518, Florida Statutes.

BACKGROUND

FMPA is a joint action agency created under Florida law and is comprised of twenty-nine municipal electric utilities across Florida. Within FMPA, the All-Requirements Project ("ARP") was formed in 1986 and currently has fifteen municipal members serving approximately 280,000 customers. Under the ARP, both generating and non-generating members are required to purchase all of their capacity and electrical energy needs from the ARP. Additionally, ARP members with generating plants commit their capacity to FMPA. FMPA will own Treasure Coast Energy Center ("TCEC") and act as the project manager for construction. The Fort Pierce

Utilities Authority ("FPUA") will operate the TCEC Unit 1 for FMPA.

The TCEC Unit 1 project will consist initially of one nominal 300-megawatt combined cycle electrical generating unit and ancillary facilities (the "Project"). The ancillary facilities include control and maintenance buildings, water treatment and storage facilities, ultra low-sulfur light oil storage tanks, cooling tower, and an electrical switchyard. An additional 900 megawatts of electrical generation facilities and ancillary facilities may be constructed on the Project site in the future, subject to subsequent approvals under the PPSA. Unit 1, and any additional units, will be primarily fueled by natural gas, with ultra low-sulfur distillate oil as a backup fuel.

The proposed Project location is at a greenfield site in the Midway Industrial Park in an unincorporated area of St. Lucie County approximately five miles west of Ft. Pierce and one-half mile east of the Florida Turnpike. The Project site, approximately 68.1 acres in size, is owned by the FMPA and is currently being used as pasture for cattle and horses. The lands surrounding the Project site are zoned for industrial uses. On July 27, 2005, the Florida Public Service Commission issued a final order determining the need for the 300-megawatt TCEC Unit 1 project pursuant to § 403.519, Florida Statutes.

At a meeting on November 1, 2005, the St. Lucie County Board of County Commissioners ("Commissioners") determined that the use of the Project site for electrical generating facilities was consistent with the County's Comprehensive Plan and granted a Conditional Use Permit and Major Site Plan Approval for use of the site for FMPA's proposed Project. With the agreement of FMPA, the Commissioners only gave approval at this November 1 meeting for two 300-megawatt units, thereby reducing the Project to an approved 600-megawatt project for purposes of St. Lucie County's land use plans and zoning ordinances.

However, the Commissioners did not disapprove of the two additional 300-megawatt units at the site, and FMPA agreed to obtain subsequent approvals from St. Lucie County prior to constructing these additional units.

On December 12, 2005, DEP issued its Staff Analysis Report. The Report contained analyses and comments by DEP and the other reviewing agencies and a set of proposed Conditions of Certification for the Project. DEP and the other reviewing agencies entered into a subsequent Stipulation stating that the agencies had no objection to the Project, subject to the inclusion of the Conditions of Certification recommended by these agencies.

After proper public notice, a consolidated land use and site certification hearing ("Hearing") on the Project was held in Ft. Pierce on February 8, 2006. Testimony of expert witnesses and various exhibits, including a revised Staff Analysis Report dated February 3, 2006, (DEP Ex. 2) were presented at the Hearing by DEP and FMPA in support of the Project. St. Lucie County was the only other agency appearing at the Hearing. One member of the general public appeared at the Hearing and testified in support of the Project. No evidence in opposition to the Project was presented at the Hearing by any agency or member of the public.

RECOMMENDED ORDERS

Administrative Law Judge, Donald R. Alexander ("ALJ"), entered his Recommended Orders concerning the Project on March 30, 2006. The ALJ's 13-page Recommended Order (Exhibit A) deals with the issue of whether the Project site is consistent and in compliance with the existing land use plans and zoning ordinances of St. Lucie County. Included in this Recommended Order is the ALJ's key conclusion that the unrebutted evidence at the Hearing established that the Project and its site are consistent and in compliance with the County's Comprehensive Plan and Land Development Code. The ALJ recommended that the Siting

Board enter a final order determining that the Project site, as described by the evidence at the final hearing, "is consistent and in compliance with existing land use plans and zoning ordinances and site-specific zoning approvals of the County."

The ALJ's 34-page Recommended Order (Exhibit B) deals with the issue of whether the Siting Board should issue a final site certification order authorizing construction and operation of the Project and approving an ultimate site capacity of 1,200 megawatts of steam electric generating capacity. In his Conclusion of Law 57, the ALJ concludes in part that:

> Competent substantial evidence produced at the certification hearing demonstrates that FMPA has met its burden of proof to demonstrate that the [Project] meets the criteria for certification under the PPSA. Unrebutted evidence . . . demonstrates that the safeguards for construction and operation of the TCEC are technically sufficient to protect the public welfare of the citizens of Florida and . . . the Project will result in minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic environment . . . Further, certification of the Project will fully balance the increasing demand for electrical power plant location and operation in this State with the broad interests of the public that are protected by the PPSA.

The ALJ recommended that the Siting Board grant final certification for the location, construction, and operation of the Project, as described in the Site Certification Application and the evidence presented at the hearing, and subject to the Conditions of Certification contained in DEP Exhibit 2.

CONCLUSION

The record in this consolidated land use and site certification proceeding case does not contain any objections to the proposed Project or any requests by governmental agencies or members of the general public that site certification of the Project should be denied. Moreover, no Exceptions were filed by any party to this proceeding objecting to any of the factual findings, legal conclusions, or recommendations of the ALJ in the two Recommended Orders now on review before the Siting Board.

Having reviewed the matters of record and being otherwise duly advised, the Siting Board concludes that, if constructed and operated as described in FMPA's Site Certification Application and by the evidence presented at the final hearing, site certification of the Project will serve and protect the broad interests of the public and should be approved.

It is therefore ORDERED:

A. The two Recommended Orders attached hereto as Exhibits A and B are adopted in their entireties and incorporated by reference herein.

B. The site of the proposed Project is hereby determined to be consistent and in compliance with existing land use plans and zoning ordinances of St. Lucie County. However, FMPA shall obtain subsequent approvals from St. Lucie County before commencing construction of any additional electrical generating units at the site beyond the two 300-megawatt units currently approved by the County.

C. Site Certification of the TCEC Unit 1 Project, as described in the Site Certification Application and the evidence presented at the final hearing, is hereby APPROVED, subject to the Conditions of Certification in DEP Exhibit 2 incorporated by reference herein.

D. Certification of the Project site for an ultimate site capacity of up to 1200-megawatts of electrical generating power is hereby APPROVED, subject to subsequent necessary approvals under the PPSA for the construction and operation of any additional units other than Unit 1.

E. Authority to assure and enforce compliance by FMPA and its agents with all of the Conditions of Certification imposed by this Final Order is hereby delegated to DEP, except that any proposed modification to burn a fuel other than natural gas or ultra low-sulfur distillate oil shall by reviewed by the Siting Board.

Any party to this proceeding has the right to seek judicial review of the Consolidated Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Final Order is filed with the clerk of the Department.

DONE AND ORDERED this 16th day of May, 2006, in Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting held on May 16th, 2006.

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

Jeb Bush

THE HONORABLE JEB BUSH
GOVERNOR

FILING IS ACKNOWLEDGED ON THIS DATE,
PURSUANT TO § 120.52 FLORIDA STATUTES,
WITH THE DESIGNATED DEPARTMENT CLERK,
RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED

Kay Buchanan 5/25/06
CLERK DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Consolidated Final Order has been sent by United States Postal Service to:

Douglas S. Roberts, Esquire
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123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314-6526

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Martha Carter Brown, Esquire
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Ann Cole, Clerk and
Donald R. Alexander, ALJ
Division of Administrative Hearings
The DeSoto Building
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Sheauching Yu, Esquire
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Haydon Burns Building
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and by hand delivery to:

Scott A. Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd.
Mail Station 35
Tallahassee, FL 32399-3000

this 25th day of May, 2006.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Chris McGuire for

J. TERRELL WILLIAMS
Senior Assistant General Counsel

3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/245-2242

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

RECEIVED
MAR 30 2006
DEPT OF ENVIRONMENTAL PROTECTION
OFFICE OF GENERAL COUNSEL

IN RE: FLORIDA MUNICIPAL POWER AGENCY TREASURE COAST ENERGY CENTER POWER PLANT SITING APPLICATION NO. PA05-48.

Case No. 05-1492EPP

RECOMMENDED ORDER

Pursuant to notice, a formal hearing was held in this matter on February 8, 2006, in Fort Pierce, Florida, before the Division of Administrative Hearings, by its assigned Administrative Law Judge, Donald R. Alexander.

APPEARANCES:

For Florida Municipal Power Agency:	Douglas S. Roberts, Esquire Hopping Green & Sams, P.A. Post Office Box 6526 Tallahassee, Florida 32314-6526
For Department of Environmental Protection:	Scott A. Goorland, Esquire Department of Environmental Protection 3900 Commonwealth Boulevard Mail Station 35 Tallahassee, Florida 32399-3000
For St. Lucie County:	Heather Young, Esquire 2300 Virginia Avenue Third Floor Annex Fort Pierce, Florida 34982-5632

STATEMENT OF THE ISSUE

The issue to be resolved in this portion of the power plant site certification proceeding is whether the site for the proposed Treasure Coast Energy Center (TCEC) is consistent and

EXHIBIT "A"

in compliance with the applicable land use plans and zoning ordinances of St. Lucie County (County), Florida, pursuant to Section 403.508(2), Florida Statutes (2005)[1].

PRELIMINARY STATEMENT

This proceeding was conducted pursuant to the Florida Electrical Power Plant Siting Act (PPSA), codified in Part II of Chapter 403, Florida Statutes, and Florida Administrative Code Chapter 62-17 to consider Florida Municipal Power Agency's (FMPA) application for power plant site certification of the TCEC Project. On April 14, 2005, FMPA filed with the Department of Environmental Protection (Department) an application for site certification for the Project. By agreement of the parties, this land use hearing was scheduled to be held on February 8, 2006, as part of the final certification hearing also held on the same date. However, separate Recommended Orders are being rendered as to the land use and certification portions of the hearing. This Recommended Order addresses the land use issues.

After appropriate notice by the Applicant and the Department, the consolidated land use and certification hearing was held on February 8, 2006, in Fort Pierce, Florida. The hearing was conducted, in part, for the purpose of receiving evidence as to whether the Project site was in compliance with the local land use plans and zoning regulations of the County.

On February 6, 2006, FMPA and the County filed a Stipulation addressing land use and zoning issues. The Stipulation indicated that the County and FMPA agreed that the site for the Project is consistent and in compliance with the County's future land use map designations and zoning ordinances and approvals.

At the hearing, FMPA presented four expert witnesses who offered testimony in the following areas: James Hay, Project overview; Stanley A. Armbruster, design of plant and associated facilities; J. Michael Soltys, Project site conditions; and Dennis J. Murphy, land use planning. Also, it offered FMPA Exhibits 1 through 15, which were received in evidence.

The Department presented Hamilton S. Oven, Jr., who is the Department Administrator for the Siting Coordination Office and was accepted as an expert. Also, it offered Department Exhibits 1 and 2, which were received in evidence.

A single set of exhibits was tendered and used at the hearing for both the land use and certification portions of the hearing; however, as noted above, separate Recommended Orders are being rendered.

The County presented no witnesses and no exhibits. No other party participated in this hearing.

Opportunity was afforded for members of the general public to appear. One member of the public, Elie J. Boudreaux, III, who is Director of the Fort Pierce Utilities Authority, offered sworn oral comments in support of the Project. No party or member of the public offered testimony or evidence contrary to the conclusion that the site for the Project is consistent and in compliance with local land use plans and zoning ordinances of the County.

Notice of the consolidated land use and site certification hearing was published by FMPA in the Fort Pierce Tribune, a local newspaper of general circulation, on December 22, 2005. Notice of the land use and certification hearing was also published by the Department on its Official Notices website on December 16, 2005, pursuant to Section 120.551, Florida Statutes.

The Transcript of the hearing was filed on March 1, 2006. On March 20, 2006, a Joint Proposed Recommended Order was filed by FMPA, the Department, and the County, and it has been substantially used in the preparation of this Recommended Order.

FINDINGS OF FACT

Based upon all of the evidence the following findings of fact are determined:

1. FMPA is a joint action agency created under Florida law and comprises twenty-nine municipal electric utilities across Florida. It was created to allow its member utilities to cooperate with each other on the basis of mutual advantage through the financing, construction, ownership, and operation of electrical generating resources. FMPA is governed by a Board of Directors consisting of one representative from each of the twenty-nine member cities. Within FMPA, the All-Requirements Project (ARP) was formed in 1986 and currently has fifteen municipal members serving approximately 280,000 customers. Under the ARP, both generating and non-generating members are required to purchase all of their capacity and electrical energy needs from the ARP. Additionally, ARP members with generating plants commit their capacity to FMPA. FMPA will own TCEC and act as the project manager for construction. The Fort Pierce Utilities Authority will operate the TCEC Unit 1 for FMPA.

2. FMPA filed with the Department a Site Certification Application (Application) for the TCEC on April 14, 2005. The Application seeks a certification under the PPSA for the construction and operation of a 300-megawatt natural gas-fired electrical generation facility, including accessory and ancillary facilities to be located in the County. The Application also seeks an ultimate site capacity determination

under the PPSA for 1,200 megawatts of electrical generating capacity on the proposed site.

3. TSEC is located in an unincorporated portion of the County. The site is located five miles southwest of Fort Pierce and eight miles northwest of Port St. Lucie and comprises approximately sixty-nine acres.

4. The site is a greenfield site currently used as active pasture for cattle and horses. It is located in the Midway Industrial Park near Fort Pierce. The site is bordered on the north and west by a rail line along Glades Cut Off Road, and to the south by an existing electrical transmission line right-of-way. Land to the east is the undeveloped industrial park. A wastewater treatment plant is proposed for a land parcel to the north of the site. Lands surrounding the site are zoned for industrial uses.

5. The TCEC will consist initially of one nominal 300-megawatt combined cycle electrical generating unit and accessory and ancillary facilities. These additional facilities include control and maintenance buildings, water treatment and storage facilities, ultra low-sulfur light oil storage tanks, cooling tower, and electrical switchyard. An additional 900 megawatts of electrical generation facilities and accessory and ancillary facilities may be constructed on the site in the future subject

to necessary approvals under the PPSA. The proposed units will be fueled primarily with natural gas with ultra low-sulfur fuel oil as a backup fuel.

6. The County has adopted its Comprehensive Plan (Plan) pursuant to the requirements of Chapter 163, Florida Statutes, and Florida Administrative Code Chapter 9J-5. That Plan has been determined to be in compliance with the requirements of Florida law. No portion of that Plan material to the Project and the site is subject to challenge in any proceeding.

7. The site has a future land use designation on the Plan's Future Land Use Map (FLUM) of Transportation/Utilities. Electrical generation facilities are an allowed use within that future land use designation.

8. The site is zoned Utilities under the Zoning District Use Regulations in the County's Land Development Code and is shown in the Utilities Zoning District on the official Zoning Map of the County. Electric generation plants are a Conditional Use in the Utilities Zoning District.

9. Conditional Uses are defined in Section 2.00.00 of the Land Development Code as a "use that is generally compatible with the use characteristics of a zoning district, but that requires individual review of its location, design, potential effect on nearby properties, and configuration in accordance

with Section 11.07.00 [of the Land Development Code] to determine the appropriateness of the use on any particular site in the district."

10. On November 1, 2005, by County Resolution 05-388, the St. Lucie County Board of County Commissioners (Commissioners) granted a Conditional Use Permit and Major Site Plan Approval for the site. That Resolution approved the use of the site for electrical generating facilities. As part of its approval of the Conditional Use Permit and Major Site Plan Approval, the Commissioners determined that the site and its use for electrical generating facilities were consistent with the adopted Plan, including the Future Land Use Element (FLUE) and accompanying FLUM.

11. During that same meeting, FMPA agreed to, and the Commissioners approved, a Conditional Use Permit and Major Site Plan Approval for only two of the originally proposed four units, thereby reducing the Project from a 1200-megawatt, four-unit Project to a 600-megawatt, two-unit Project for purposes of the County's zoning approvals. FMPA also agreed to obtain additional zoning reviews and approvals prior to the construction of the third and fourth units proposed at the site. By its zoning action, the Commissioners did not disapprove additional future units.

12. Resolution 05-388 contains certain conditions related to the Project and the site and a site plan for the use of the site. These conditions relate to an updated landscape plan, construction traffic mitigation plans, a limitation on the fuels to be used at the site without further approval by the Commissioners, and annual contributions by FMPA toward environmental protection in the County.

13. FMPA is able to design, construct, and operate the Project in full compliance with the conditions contained in the Conditional Use Permit and Major Site Plan Approval.

CONCLUSIONS OF LAW

14. The Division of Administrative Hearings has jurisdiction of the parties and the subject matter of this proceeding pursuant to Sections 120.569, 120.57 and 403.508(2), Florida Statutes.

15. In accordance with Chapter 403, Florida Statutes, and Florida Administrative Code Chapter 62-17, proper public notice was accorded all persons, entities, and parties entitled to such notice. All necessary and required governmental agencies, as well as members of the public, either participated in or had the opportunity to participate in the land use hearing.

16. The applicable land use plans and zoning ordinances for the Project and its site are those adopted by the County.

For purposes of the land use hearing, under Section 403.508(2), Florida Statutes, the applicable "land use plan" is the Plan's FLUE and the accompanying FLUM. The applicable zoning ordinances for the Project and its site are contained in the Land Development Code and in the Conditional Use Permit issued by the Commissioners.

17. Unrebutted evidence at the hearing demonstrates that the Project and its site are consistent and in compliance with the County's Plan and are consistent and in compliance with the Land Development Code. Additional zoning reviews will be necessary prior to the certification of generating capacity above the initial 600 megawatts.

RECOMMENDATION

Based upon the foregoing Findings of Fact and Conclusions of Law, it is

RECOMMENDED that the Siting Board enter a final order determining that the Treasure Coast Energy Center Project and its site, as described by the evidence presented at the hearing, are consistent and in compliance with existing land use plans and zoning ordinances and site-specific zoning approvals of the County, pursuant to Section 403.508(2), Florida Statutes.

DONE AND ENTERED this 30th day of March, 2006, in Tallahassee, Leon County, Florida.

DONALD R. ALEXANDER
Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-3060
(850) 488-9675 SUNCOM 278-9675
Fax Filing (850) 921-6847
www.doah.state.fl.us

Filed with the Clerk of the
Division of Administrative Hearings
this 30th day of March, 2006.

ENDNOTE

1/ All subsequent references are to the 2005 version of the Florida Statutes.

COPIES FURNISHED:

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NOTICE OF RIGHT TO FILE EXCEPTIONS

All parties have the right to submit written exceptions within 15 days of the date of this Recommended Order. Any exceptions to this Recommended Order should be filed with the agency that will render a final order in this matter.

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: FLORIDA MUNICIPAL POWER)
AGENCY TREASURE COAST ENERGY)
CENTER POWER PLANT SITING)
APPLICATION NO. PA05-48.)

Case No. 05-1492EPP

RECOMMENDED ORDER

Pursuant to notice, a formal hearing was held in this case on February 8, 2006, in Fort Pierce, Florida, before the Division of Administrative Hearings, by its assigned Administrative Law Judge, Donald R. Alexander.

APPEARANCES:

For Florida Municipal Power Agency:	Douglas S. Roberts, Esquire Hopping Green & Sams, P.A. Post Office Box 6526 Tallahassee, Florida 32314-6526
For Department of Environmental Protection:	Scott A. Goorland, Esquire Department of Environmental Protection 3900 Commonwealth Boulevard Mail Station 35 Tallahassee, Florida 32399-3000
For St. Lucie County:	Heather Young, Esquire 2300 Virginia Avenue Third Floor Annex Fort Pierce, Florida 34982-5632

STATEMENT OF THE ISSUE

The issue to be resolved in this portion of the proceeding is whether the Siting Board should issue a final certification to the Florida Municipal Power Agency (FMPA) to construct and operate the Treasure Coast Energy Center (TCEC) Unit 1 and an ultimate site capacity determination of 1,200 megawatts of steam electric generating capacity to be located at the TCEC, in accordance with the provisions of the Florida Electrical Power Plant Siting Act (PPSA).

PRELIMINARY STATEMENT

This site certification proceeding has been conducted in accordance with the PPSA codified in Part II, Chapter 403, Florida Statutes (2005)[1], and Florida Administrative Code Chapter 62-17 to consider FMPA's Site Certification Application (Application) for the TCEC Project (the Project). On April 14, 2005, FMPA filed with the Department of Environmental Protection (Department) its Application for site certification for the Project. That Application was also distributed to several reviewing agencies.

On July 27, 2005, the Florida Public Service Commission (FPSC) issued its Final Order determining the need for the Project pursuant to Section 403.519, Florida Statutes.

On December 12, 2005, the Department issued its Staff Analysis Report (Report) concerning the Project, as required by Section 403.507(4), Florida Statutes. That Report contains reports prepared by other reviewing agencies, along with a compiled set of proposed Conditions of Certification for the Project as proposed by the Department and other reviewing agencies. On February 8, 2006, the Department submitted at the site certification hearing its Revised Staff Analysis Report as Department Exhibit 2 to update and correct various matters in the earlier version of its Report.

After proper public notice by both FMPA and the Department, a consolidated site certification hearing and land use hearing was held in Fort Pierce, Florida, on February 8, 2006, as required by Section 403.508(3), Florida Statutes. The purpose of the certification hearing was to receive oral, written, and documentary evidence concerning whether, through available and reasonable methods, the location and operation of the proposed Project would produce minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life in an effort to fully balance the increasing demands for electrical power plant location and operation with the broad interests of the public. See § 403.502, Fla. Stat.

Prior to the hearing, FMPA and several reviewing agencies entered into Stipulations, including the Florida Department of Transportation (FDOT), the Florida Department of Community Affairs (DCA), the Florida Fish and Wildlife Conservation Commission (FFWCC), the South Florida Water Management District (SFWMD), the Treasure Coast Regional Planning Council (TCRPC), and the Department, indicating that those agencies did not object to certification subject to inclusion of those agencies' recommended Conditions of Certification.

Notice of the consolidated land use and site certification hearing was published by FMPA in the Fort Pierce Tribune on December 22, 2005. Notice of the consolidated land use and site certification hearing was also published by the Department on its Official Notices website on December 16, 2005, pursuant to Section 120.551, Florida Statutes.

At the certification hearing, FMPA presented five expert witnesses who testified in the following areas: James Hay, FMPA organization and Project need; Stanley A. Armbruster, design of plant and associated facilities; Timothy M. Hillman, air quality permitting and environmental project management; J. Michael Soltys, managing, coordinating, and completing permitting and regulatory requirements; and Dennis J. Murphy, land use and transportation planning. Also, it offered FMPA Exhibits 1 through 15, which were received in evidence. Finally, by agreement of the parties, the prefiled written testimony and exhibits of those five witnesses, and eight other witnesses, Dr. Ralph E. Brooks, James M. Andersen, Brian J. Klausner, Girma Mergia, Michael J. Tuttle, Kenneth R. Weiss, John M. Wynne, and Roosevelt R. Huggins, were received in evidence as FMPA Exhibit 3.

The Department presented the testimony of Hamilton S. Oven, Jr., who is the Administrator for the Siting Coordination Office and was accepted as an expert. Also, it offered Department Exhibits 1 and 2, which were received in evidence.

A single set of exhibits was tendered and used by the parties for both the land use and site certification phases of the hearing; however, separate Recommended Orders are being rendered for each portion of the hearing.

St. Lucie County (County) presented no witnesses and no exhibits. No other party participated in this hearing.

Opportunity was afforded for members of the general public to appear. One member of the public, Elie J. Broudreaux, III, who is director of the Fort Pierce Utilities Authority (FPUA), offered sworn oral comments in support of the Project. No party or member of the public offered testimony or evidence contrary to the conclusion that the Project should be granted certification under the PPSA, subject to the Department's recommended conditions of certification.

The Transcript of the hearing was filed on March 8, 2006. A Joint Proposed Recommended Order was filed by FMPA and the Department on March 20, 2006, and has been substantially used in the preparation of this Recommended Order.

FINDINGS OF FACT

Based upon all of the evidence, the following findings of fact are determined:

1. FMPA is a joint action agency created under the Florida Interlocal Cooperation Act of 1969 (Section 163.01, Florida Statutes) and the Joint Power Act (Part II, Chapter 361, Florida Statutes). FMPA comprises twenty-nine municipal electric utilities across Florida and was created to allow its member utilities to cooperate with each other on the financing, construction, ownership, and operation of electrical generating resources. FMPA is governed by a Board of Directors consisting of one representative from each of the twenty-nine member cities. Within FMPA, the All-Requirements Project (ARP) was formed in 1986 and currently has fifteen municipal members serving approximately 280,000 customers. Under the ARP, both generating and non-generating members purchase all of their capacity and electrical energy needs from the ARP. Additionally, ARP members with generating plants commit their capacity to FMPA. FMPA will own the TCEC and act as the project manager for construction. The FPUA will operate Unit 1 for FMPA.

2. FMPA's proposed TCEC will be located in the County, approximately five miles west of the City of Fort Pierce and eight miles north of the City of Port St. Lucie.

3. Much of the site's northwestern boundary is determined by a Florida East Coast Railroad line that parallels Glades Cut-Off Road. To the south, the site is bordered by the North St. Lucie River Water Control District's Canal 102 with a Florida Power and Light Company (FPL) electrical transmission line right-of-way across the southern part of property and adjacent to Canal 102. The parcel north of the proposed site is owned by the FPUA and is proposed for a mainland wastewater treatment plant. The land directly east of the site is largely undeveloped industrial park. The proposed plant site itself is located within the Midway Industrial Park. The site is approximately one-half mile east of the Florida Turnpike and one-half mile north of Midway Road.

4. The site contains approximately 68.1 acres. Land use and vegetation at the site consist primarily of pasture used for cattle and horses. Within the pasture land are areas of wet prairie, freshwater marsh, and Brazilian Pepper. The site was historically and most likely pine flatwoods or savannah, based on the characteristics of the surrounding vicinity. However, due to past clearing and agricultural activities, the site has been significantly altered from its natural state and has little native vegetation. Current vegetation reflects the disturbed condition of the site. There were no observations or indications of protected plant or wildlife species on the site.

5. The site is located in an area outside the 500-year flood plain as determined by the Federal Emergency Management Agency.

6. The future land use map in the County's Comprehensive Plan indicates no expected changes in the land use patterns for the site or the adjacent land area in the future, indicating that the site will continue to be compatible with the predominant land use in the immediate Project vicinity. As part of its land development approvals for the site, the St. Lucie Board of County Commissioners determined that the Project was compatible with surrounding land uses.

7. FMPA proposes to construct a nominal 300-megawatt combined cycle electrical generating unit at the site known as Unit 1. FMPA is also requesting an ultimate site capacity determination for a total of 1,200 megawatts of generating capacity to be located at the Project site. Any future electrical generating units after the first two units up to the proposed ultimate site capacity of 1,200 megawatts will require additional zoning review and approval and any other applicable County development authorization at the time those units are proposed for approval.

8. Unit 1 will be dual fuel, with natural gas as the primary fuel and ultra low sulfur diesel fuel oil as a backup fuel. The Project will be a "one-on-one" combined cycle unit.

Unit 1 will be comprised of a combustion turbine, a heat recovery steam generator (HRSG), and a single steam turbine generator.

9. In the combustion turbine, fuel is combusted in the form of hot gases which expand through the turbine. The combustion turbine spins the electrical generator that is directly connected, producing power. About half of the energy of the hot gases is extracted when expanded through the combustion turbine. The remainder of the heat is exhausted into a HRSG. These hot gases flow through the HRSG which turns water into steam. The steam flows into a steam turbine, spinning a second electrical generator. The steam is then exhausted into a condenser, where it is condensed back into water and pumped back to the HRSG.

10. The HRSG will also be equipped with duct firing to provide peak power by increasing the steam production in the HRSG, which increases the output from the steam turbine generator.

11. The Unit will also be able to operate in a steam turbine bypass operation where the combustion turbine and HRSG will operate normally but the steam will bypass the steam turbine. This mode of operation will be employed during startups and will also allow unit operation when the steam turbine/generator is not available.

12. Combined cycle generation technology is very efficient because it generates electrical energy from the fuel input, both directly through the combustion turbine and indirectly through capture of the energy in the combustion turbine exhaust gas in the HRSG. This captured energy is used to produce steam to drive the separate steam turbine electrical generator. By reheating the steam between sections of the steam turbine, additional improvements and cycle efficiency can be achieved. Combined cycle technology makes the most of the input fuel, achieving increased efficiency in the generation of electrical energy. It achieves efficiencies of 55 percent in converting fuel into electricity. For these reasons, the modern combined cycle power plant is one of the most efficient power cycles available. If properly maintained and operated, the life expectancy of a combined cycle unit is indefinite.

13. Combined cycle units operating on natural gas, such as Unit 1, are one of the cleanest sources of fossil generation. These units also use considerably less water than traditional steam turbine units, requiring approximately one-half the amount of water used by a steam cycle only unit with similar electrical output.

14. The ultimate site arrangement for the Project allows for the installation of three future similar-sized combined cycle units for an ultimate site certification capacity of

approximately 1,200 megawatts. FMPA will clear and develop the entire Project site during the construction for Unit 1.

15. A cooling tower used to cool the steam turbine condenser will be located to the north of Unit 1. The cooling tower will consume approximately 95 percent of all the water used by the Project. For this Project, reclaimed water will be supplied from FPUA's soon-to-be constructed water reclamation facility, which will be located just north of the site. The reclaimed water will be used as cooling tower makeup. Until the water reclamation plant comes online, the new Unit 1 will utilize water withdrawn from the Upper Floridan Aquifer for cooling. The cooling tower design will be a multiple cell, mechanical draft, counter flow cooling tower.

16. Access to the site will be over Energy Drive, which is an access road in the adjacent industrial park.

17. Unit 1 will be interconnected to the FPL electrical transmission system. A new electrical switchyard will be constructed on the site. Two new transmission lines will connect the site to an existing nearby FPL electrical substation and electrical transmission system. The new transmission lines will be installed on new structures for the entire length of each transmission line. Each of the two new lines will be approximately three miles long. One line will parallel Glades Cut-Off Road to the southwest and connect to the existing FPL

Midway/Turnpike transmission line. The second line will go west from the Project site, cross Glades Cut-Off Road parallel to an existing road and FPL transmission line, cross over the Florida Turnpike and Interstate 95, and then turn south into the FPL Midway electrical substation. Each corridor is one-fourth mile wide for most of its length. It is expected that a final right-of-way will be acquired parallel to Glades Cut Off Road for one transmission line and a final right-of-way will be acquired for the second transmission line parallel to the existing FPL right-of-way.

18. The new transmission line structures will be self-supporting concrete tubular steel or hybrid concrete-tubular steel poles or a combination of these options. The typical aboveground height of the transmission structures will be approximately one hundred feet. The structures will be placed approximately four hundred to eight hundred feet apart along the route. The lines will be designed to meet the clearance requirements of the National Electrical Safety Code for the minimum ground clearance of twenty-six feet. The two lines will also comply with the Department's electric and magnetic fields limits in Florida Administrative Code Chapter 62-814.

19. These two transmission line corridors were selected as the most direct means with the least impact for connecting into the FPL transmission network. The transmission lines are

located in areas zoned for commercial, industrial, and agricultural uses. No housing units will be moved as part of the Project and no residential areas will be impacted. The transmission lines will be constructed completely within or adjacent to existing rights-of-way which provide minimal ecological value.

20. A new natural gas pipeline up to sixteen inches in diameter is proposed to connect the site with the Florida Gas Transmission gas pipeline. This existing gas main is located approximately 3,700 feet southwest of the site, near the Florida Turnpike. A 1,320-foot wide corridor centered on Glades Cut Off Road from the Florida Turnpike to the site is proposed for certification. A seventy-five-foot wide temporary easement for pipeline installation and a permanent forty-foot right-of-way are anticipated. It is expected that the natural gas pipeline will be constructed within or adjacent to the existing Florida East Coast Railroad corridor or adjacent to Glades Cut Off Road. The pipeline will be manufactured according to American Petroleum Institute standards and will be built in accordance with United States Department of Transportation and FPSC safety requirements.

21. The proposed gas pipeline corridor is located in areas zoned for commercial and utility uses. No residential areas will be impacted during construction of the underground

pipeline. The existing railroad right-of-way is expected to be maintained as a transportation corridor and provides minimal ecological value. There will be minimal impacts to vegetation in the gas pipeline right-of-way as there will be only minor clearing required for construction. Disturbed lands will be returned to maintained right-of-way condition following construction.

22. Fuel oil for use in the unit will be delivered by truck. A complete fuel unloading, storage, and supply system will be installed at the site. The unloading station will be designed for containment of a fuel spill. Double-walled piping will be used for underground piping running through the unloading station to the storage tank and from the tank to the combustion turbine. A one-million gallon aboveground storage tank will be installed to provide approximately three days of fuel oil at full load operation for Unit 1. This will be a single wall tank fabricated from carbon steel and will be installed inside a dike containment area. The containment area will be provided with a synthetic liner sufficiently impermeable to ensure no oil can escape by infiltrating through the liner into the soil or into surface or groundwaters.

23. The major water use during operation of Unit 1 will involve cooling tower operation. This is the highest volume water consumer for the Project. The cooling system will use

approximately 2.52 million gallons per day of treated wastewater, most of which is evaporated to the atmosphere in the cooling process. Other plant non-cooling water uses will include the plant service water system. This system supplies fire water, miscellaneous process uses, and makeup water to the demineralizer system. The demineralizer system provides boiler makeup water and provides water for control of nitrogen oxides when firing oil in the unit.

24. Treated sewage effluent or reclaimed water will be used for cooling tower makeup water. This reclaimed water will be provided by the FPUA wastewater treatment plant proposed to be located north and adjacent to the site. This treatment plant is expected to be online in late 2009. The reclaimed water will be supplied via pipeline across the site. It will be necessary to utilize groundwater for cooling purposes until the wastewater treatment plant is online. Groundwater will also be used when the wastewater treatment is offline and unable to supply treated effluent in the future.

25. Three new onsite wells pumping from the Upper Floridan Aquifer will supply fire water and service water. The wells will supply water to the steam cycle and makeup treatment system and the evaporative cooling makeup. They will also provide a temporary water supply for cooling tower makeup. The wells will be sized so that two of the wells will be able to provide the

required water flow at full load with a third well as a backup. An average of 2.95 million gallons per day of groundwater will be used prior to the availability of reclaimed water. An average of approximately 129,000 gallons per day of groundwater will be needed under average annual conditions for non-cooling water needs of the plant.

26. Cooling tower blowdown from Unit 1 will be conveyed to the FPUA wastewater treatment plant for treatment and disposal. Approximately 586,000 gallons per day of cooling tower blowdown wastewater will be returned to the FPUA system for disposal. The cooling tower system will operate at three cycles of concentration when using groundwater, which is considered the maximum practical limit to prevent scaling of heat transfer systems within the cooling system. When reuse water is available, the cooling towers will operate at four cycles of concentration, which further minimizes the amount of water needed for cooling. The cooling system is also designed to minimize the amount of cooling tower blowdown and makeup that is required.

27. Potable water for the site will be provided through an extension from the FPUA municipal water system. This connection will also supply the evaporative cooler needs on the Unit and backup water supply to the plant service water system.

28. Water treatment and other water uses in Unit 1 will generate various process wastewaters. Wastewaters from the onsite demineralizer system, including filter backwash and reverse osmosis reject wastewater, will be routed to an onsite wastewater sump for disposal to the FPUA wastewater treatment plant. The HRSG and boiler piping will be chemically cleaned during commissioning of the new unit and the steam generators will be cleaned infrequently over the life of the unit. Chemical cleaning solutions will be neutralized onsite if required and transported offsite by a licensed waste disposal contractor. Sanitary wastewater will be routed to the FPUA municipal sanitary treatment system for treatment and disposal.

29. The TCEC design contains several features to minimize impacts of project wastewaters to surface and groundwaters. The cooling system design will minimize the amount of cooling tower blowdown and makeup required. There will be no process wastewater discharge to groundwater or surface waters at the plant site. All process and sanitary wastewaters will be returned to FPUA for final disposal. Further, the use of reclaimed and treated wastewater in the cooling system will reduce the quantity of wastewater that would otherwise have to be disposed of to surface and groundwaters. Groundwater consumption will also be reduced through the use of treated wastewater for cooling and by recovering and pumping blowdown

water from the HRSG to the cooling towers as makeup rather than sending the blowdown to the wastewater collection and disposal system.

30. Groundwater withdrawals during initial operation of Unit 1 are proposed from the Upper Floridan Aquifer for cooling tower makeup until future sources of treated wastewater become available for the Project to displace groundwater withdrawals. Analyses were performed to determine the impact of these groundwater withdrawals from the non-potable Upper Floridan Aquifer. A three-dimensional aquifer analysis computer model was developed to model these impacts. The computer model was one developed by the United States Geological Survey and approved by the SFWMD. The drawdown in the Floridan Aquifer was simulated for the condition of groundwater withdrawals for Unit 1 of 3.2 million gallons per day. This assessment indicates that the onsite pumping from the Upper Floridan Aquifer would have a small impact on existing legal groundwater users in the area. This modeling predicts that the additional two- and one-foot drawdowns in the Upper Floridan Aquifer due to the plant withdrawals at maximum withdrawal rates would occur at 1.8 and 5.8 miles, respectively, from the Project. This limited impact in drawdown of the Floridan Aquifer and the magnitude of the drawdown increase are not considered significant. The proposed groundwater pumping is not expected to cause salt water

intrusion into the Floridan Aquifer. Due to the presence of a 600-foot thick Hawthorne formation and the upward gradient from the Upper Floridan Aquifer to the land surface, no adverse effects to surface wetlands are expected. The SFWMD agreed with these conclusions as indicated in its report submitted to the Department. Impacts on the Upper Floridan Aquifer after the Project begins operation using reclaimed water will be significantly reduced and also cause no adverse impacts.

31. Project construction may require dewatering for placement of subsurface facilities, such as piping, electrical trenches, sumps, and foundations. Dewatering impacts for construction were estimated using site specific geotechnical information. Due to the short duration of the onsite dewatering, it will not affect existing users and will have a minimal and temporary impact on the surficial water table aquifer. No impact is expected to extend beyond the project site boundaries.

32. Of the 68.1-acre Project site, 11.96 acres constitute wetlands. Three onsite wetlands will be lost due to the site development, comprising 11.25 acres of wetlands. The onsite wetlands were delineated in accordance with state and federal guidelines for such delineations. These onsite wetlands are low quality herbaceous wetlands, mainly disturbed wet prairie and freshwater marshes. Cattle have access to the entire site

including these wetlands. Natural vegetation and wildlife have been largely eliminated from the Project site and much of the surrounding vicinity due to onsite grazing and past development activities, including residential, industrial, and commercial development. Based on these considerations, the loss of vegetation and associated wildlife habitat at the Project site will be insignificant.

33. FMPA must mitigate for the unavoidable wetlands impacts due to site development. FMPA has entered into a mitigation credit purchase and sale agreement with the Bluefield Ranch Mitigation Bank (located in the County) to compensate for those wetlands impacts subject to state jurisdiction.

34. There will be no impacts to surface waters from operation of the facility. The Project will not withdraw or discharge wastewaters to surface waters. The onsite stormwater management system will be designed to comply with all applicable state and local regulations regarding discharge into offsite surface waters. The stormwater management system will meet the water quality treatment requirements of the Department and SFWMD, as well as the standards of the County. Runoff originating from potentially contaminated areas, such as miscellaneous plant drains and drainage from oil containment areas, will be routed through an oil/water separator. Oil and grease will be removed from the contaminated stormwater, and the

treated effluent will be collected and discharged to the FPUA wastewater treatment plant. Captured oil and grease will be properly disposed offsite. Runoff from other potentially contaminated areas, such as storage tank containment areas, will be contained locally.

35. All runoff from the fenced site will be directed to the onsite stormwater detention basin for treatment and discharge in accordance with applicable stormwater rules. Peak stormwater discharges from the Project area are less than the peak stormwater discharges from the pre-Project site for the same storm event. Therefore, the potential for local flooding will not be affected by the Project.

36. During construction, a combination of silt fencing, straw bale sediment barriers, and a stormwater detention pond will be used to control erosion on the site and to reduce the potential for transport of loaded sediment offsite. Grading will be accomplished in phases and each graded area will be seeded and mulched after construction is completed. During operation, stormwater ditches will route stormwater to the onsite stormwater detention area. This basin will meet the stormwater treatment quality and quantity requirements of the Department, SFWMD, and County. Thus, there will be minimal adverse impact from the management and storage of surface waters on the site.

37. Air emissions from the Project are subject to review under federal and state regulations, primarily the Prevention of Significant Deterioration (PSD) permitting program. The Department regulates major air pollution facilities, such as Unit 1, in accordance with the PSD program under Florida Administrative Code Rule 62-212.400. The PSD pre-construction review is required in areas currently in attainment with the state and federal ambient air quality standards. The County is an attainment area for those air quality standards. The state PSD regulations are designed to assure that the air quality in existing attainment areas like the County does not significantly deteriorate or exceed the ambient air quality standards while providing a margin for future industrial and commercial growth.

38. The PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction. A major stationary source is defined for PSD permitting purposes as any one of twenty-eight listed major source categories which emits or has the potential to emit one hundred tons per year or more of any regulated pollutant. The Unit 1 Project is one of the twenty-eight major listed category types, a fossil fuel-fired steam electric plant, and has the potential to emit greater than one hundred tons per year of at least one of the PSD regulated pollutants. Unit 1 also exceeds the PSD significant emission levels for several pollutants and

is thus subject to PSD review as a major stationary source. The emissions from Unit 1 subject to PSD review include nitrogen oxides (NOx), sulfur dioxide, carbon monoxide (CO), particulate matter (PM), particulate matter less than ten microns in aerodynamic diameter (PM10), and sulfuric acid mist.

39. The PSD review requires an analysis of best available control technology (BACT), an air quality impact analysis, and an assessment of the Project's impacts on general commercial residential and commercial growth, soils and vegetation, and visibility, as well as impacts to air quality in Class I areas.

40. BACT is defined as an air emission limitation based on the maximum degree of pollutant reduction for emissions, determined on a case-by-case basis, considering technical, economic, energy, and environmental factors, as well as other costs for the control of each pollutant. The facilities at the Project subject to BACT review include the combustion turbine, the fuel oil storage tank, a diesel driven fire pump and oil storage tank, a safe shutdown generator and storage tank, and the mechanical-draft cooling tower. A BACT analysis was performed for each of these emission sources. The analysis was conducted using the "top down" methodology described by the United States Environmental Protection Agency (EPA).

41. Based upon this analysis, best available control technologies for controlling NOx emissions from Unit 1 were

determined by the Department during its PSD review to be the use of dry low NOx burners within the combustion turbine and selective catalytic reduction (SCR) installed in the HRSG to achieve an emission limit of 2.0 parts per million of NOx when burning natural gas. The Department also determined during its PSD review that when burning fuel oil, BACT to control NOx emissions was the use of water injection with a SCR to achieve an emission limit of 8.0 parts per million. The Department agreed with FMPA's proposed NOx emission limit for this Project.

42. For carbon monoxide emissions, BACT control was determined by the Department during its PSD review to be good combustion controls and practices. Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Most combustion turbines incorporate good combustion practices based on high temperature and other techniques to minimize emissions of CO. The Department further determined during its PSD review that the BACT for CO was 4.1 parts per million for natural gas firing and 8.0 parts per million for fuel oil firing. A continuous limit of 8.0 parts per million CO on a twenty-four hours basis will also be implemented for both gas and oil firing with or without the duct burner in operation. In addition, an annualized limit of 6.0 parts per million of CO will also be included to recognize that Unit 1 will be operated in the normal natural gas-fired mode.

43. BACT for particulate emissions, both PM and PM10, was determined by the Department during its PSD review to be a fuel selection of natural gas and ultra low sulfur fuel oil and good combustion controls.

44. Sulfur dioxide and sulfuric acid mist control was determined by the Department in its PSD review to be the use of low sulfur fuels, including the limited use of ultra low sulfur diesel fuel.

45. The cooling tower can produce PM emissions in the small amounts of water entrained in the air passing through the cooling tower that can be carried out of the tower, known as "drift" droplets. These droplets contain impurities from the cooling water which can be classified as an emission. FMPA proposed, and the Department accepted during its PSD review, that use of high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005 percent constitutes BACT for these drift emissions. Modeling of the impacts of the emissions and plume from the cooling tower indicates that there would be no environmental impact.

46. Finally, the Department concluded during its PSD review that the use of ultra low sulfur fuel oil and limited hours of operations (five hundred hours or less) insures that emissions from both the onsite safe shutdown generator and the diesel engine fire pump will be minimal. An air quality impact

analysis was also conducted for the Project-related air emissions, in accordance with the Department's and EPA's air dispersion modeling guidelines. The ambient air quality impact analysis conducted for Unit 1 demonstrates that this Project will not have a significant impact on air quality near the Project site or in the nearest Class I air quality areas, including the Everglades National Park. There are no predicted air quality impacts greater than the PSD significant impact levels. Therefore, under the PSD program, no further air quality impact analysis was required for the Project.

47. The Project is not expected to cause any adverse impacts on vegetation, soils, or visibility in the Project area or at the nearest Class I areas.

48. The Project construction activities may produce air emissions during onsite construction of buildings and from construction equipment exhaust. Particulate matter would be the major source of air pollution during construction. These emissions are expected to be intermittent, short term, and composed of relatively-large particles. These particles tend to settle out quickly and will not generally leave the Project site. Particulate matter emissions will be controlled by watering and application of dust suppressants or ground covers as necessary in active work areas.

49. Construction and operation of the Project will result in significant economic benefits to the County, the region, and the State of Florida. No significant permanent adverse socioeconomic impacts are expected. The anticipated benefits of the Project include primarily the direct and indirect employment and earnings impacts that will be realized in the area from construction and operation. The Unit 1 construction will create approximately 286 temporary jobs, with an estimated payroll of $23.6 million over a twenty-two-month period. It is expected that most of these jobs will be filled by workers already residing in or near the County. The in-migration of construction employees will be small and should not increase the demand for services from local governments and nearby service providers. Information gathered for the Project indicates that more than enough service capacity is available to accommodate the construction work force. Individuals temporarily relocating to the area during construction should not have a problem securing affordable housing. The indirect socioeconomic impacts from construction of the Project include the creation of service jobs in the area to accommodate construction workers. Using an accepted economic multiplier, it is expected that 762 additional jobs may be created as a result of the construction. Expenditure of the construction payroll in the local economy will be passed along to local businesses through spending by

construction workers and the governments in the form of taxes. Benefits from operation of the Project will occur from the sixteen operational personnel needed to operate the combined cycle units. The annual payroll for these employees is estimated to be $1.38 million. It is expected that these employees will come from the existing FPUA work force. Since operational personnel tend to live near the facility they operate, the majority of the annual payroll will remain within the local economy. Indirect socioeconomic impacts will include the creation of up to sixteen additional fulltime indirect jobs as a result of the operation of the combined cycle project.

50. By its Order dated July 27, 2005, the FPSC found that there is a need for the proposed Unit 1, taking into account the need for electric system reliability and integrity. The FPSC found that Unit 1 was required to maintain FMPA's winter and summer reserve margins. The FPSC also found that Unit 1 will enhance the reliability and integrity of FMPA's electric system through the use of the highly efficient combined cycle technology with the ability to burn two different types of fuel. The two interconnections to FPL's transmission system would also be a benefit to Unit 1 and allow FMPA to better serve its members in the FPL transmission grid. FMPA's analysis of five proposals from other potential bidders indicated that Unit 1 is the most cost-effective option available. There were no

conservation measures taken by or reasonably available to FMPA which would mitigate the need for the proposed Unit 1. Unit 1 was further found by the FPSC to provide the most cost-effective solution to satisfy FMPA's forecast capacity requirements beginning in 2008.

51. The Department, DCA, FPSC, SFWMD, FDOT, FFWCC, TCRPC, and the Cities of Fort Pierce and Port St. Lucie each prepared written reports on the Project.

52. The Department has proposed Conditions of Certification for the Project, which FMPA has agreed to accept and comply with in construction and operation of the Project.

53. No state, regional, or local agency has recommended denial of certification of the Project.

CONCLUSIONS OF LAW

54. The Division of Administrative Hearings has jurisdiction of the parties and the subject matter of this proceeding pursuant to Sections 120.569, 120.57, and 403.508(3), Florida Statutes.

55. In accordance with Part II of Chapter 403, Florida Statutes, and Florida Administrative Code Chapter 62-17, proper notice was accorded all persons, entities, and parties entitled to such notice. All necessary and required governmental agencies, as well as members of the public, either participated in or had the opportunity to participate in the certification

hearing. Reports and studies were issued by the Department, DCA, FFWCC, SFWMD, FDOT, TCRPC, City of Fort Pierce, and City of Port St. Lucie.

56. The FPSC has issued its affirmative determination that a need exists for the electrical generating facility and the electricity it will produce in accordance with Section 403.519, Florida Statutes.

57. Competent substantial evidence produced at the certification hearing demonstrates that FMPA has met its burden of proof to demonstrate that the TSEC meets the criteria for certification under the PPSA. Unrebutted evidence produced at the hearing demonstrates that the safeguards for construction and operation of the TCEC are technically sufficient to protect the public welfare of the citizens of Florida and are otherwise reasonable and available methods to achieve that protection of the public. The Project will result in minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life. In addition, and as noted in a separate Recommended Order, the Project will not conflict with the State Comprehensive Plan or the County Comprehensive Plan. If operated and maintained in accordance with this Recommended Order and the Department's proposed Conditions of Certification, the TCEC will comply with the applicable non-procedural

requirements of all agencies. Further, certification of the Project will fully balance the increasing demand for electrical power plant location and operation in this State with the broad interests of the public that are protected by the PPSA.

RECOMMENDATION

Based upon the foregoing Findings of Fact and Conclusions of Law, it is

RECOMMENDED that the Siting Board grant final certification to the Treasure Coast Energy Center Project under Part II, Chapter 403, Florida Statutes, for the location, construction, and operation of the Project, representing a 1,200 megawatts combined cycle unit site with Unit 1 being a nominal 300-megawatt combined cycle unit, as described in the Site Certification Application and the evidence presented at the certification hearing, and subject to the Conditions of Certification contained in Department Exhibit 2.

DONE AND ENTERED this 30th day of March, 2006, in Tallahassee, Leon County, Florida.

Donald R. Alexander

DONALD R. ALEXANDER
Administrative Law Judge
Division of Administrative Hearings
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Filed with the Clerk of the
Division of Administrative Hearings
this 30th day of March, 2006.

ENDNOTE

1/ All future references are to the 2005 version of Florida Statutes.

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NOTICE OF RIGHT TO FILE EXCEPTIONS

All parties have the right to submit written exceptions within 15 days of the date of this Recommended Order. Any exceptions to this Recommended Order should be filed with the agency that will render a final order in this matter.

CONDITIONS OF CERTIFICATION

I. GENERAL

The following general and specific Conditions shall apply to the construction and operation of the Florida Municipal Power Agency (FMPA) Treasure Coast Energy Center (TCEC) power plant project.

A. Definitions

The meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, 372, and 253, Florida Statutes (F.S.), and any regulation adopted pursuant thereto and the applicable statutes and regulations of any agency with jurisdiction over the Facility. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the Department. As used herein:

1. "Application" shall mean the Site Certification Application (SCA) as filed, supplemented or amended by the Licensee, Florida Municipal Power Agency (FMPA) for the site and TCEC.

2. "Conditions" shall mean these Conditions of Certification.

3. "DEP" or "Department" shall mean the Florida Department of Environmental Protection.

4. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, including but not limited to conditions necessitating new or replacement gas pipeline, transmission lines, or access facilities.

5. "Project", "Facility" or "power plant" shall mean the Licensee's TCEC facility, which is located on an approximately 68.1 acre site in St. Lucie County, Florida. The Facility includes a natural gas-fired combined cycle system, a steam turbine electrical generator, a cooling tower, air pollution control equipment, a fuel handling and storage areas, 230 kV transmission lines and related equipment and facilities, as described in the Application.

6. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

7. "FWCC" shall mean the Florida Fish and Wildlife Conservation Commission.

8. "Licensee" or "Permittee" shall mean an applicant that has obtained a certification order for the subject electrical power plant. In this instance, the FMPA is the Licensee.

9. "SFWMD" shall mean the South Florida Water Management District.

10. "PERMITTING AUTHORITY" shall mean the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.

11. "COMPLIANCE AUTHORITY" shall mean the Department of Environmental Protection Southeast District, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401.

B. Applicable Rules

The construction and operation of the Licensee's Facility shall be in accordance with all of the applicable provisions of at least the following regulations of DEP: Chapters 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, 62-762, 62-769, 62-770 and 62-814, Florida Administrative Code (F.A.C.), or their successors if they are renumbered

II. CHANGE IN DISCHARGE

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any regulated pollutant not identified in the Application at regulated levels, or more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any anticipated Facility expansions beyond the certified initial generating capacities of the units described in the Application, production increases, or process modifications which may result in new, different, or increased discharges of pollutants, or expansion in steam generation capacity shall be reported by submission of an amendment or application for modification or application for certification pursuant to Chapter 403, F.S.

III. GENERAL CONDITIONS

A. Facilities Operation

1. The Licensee shall properly operate and maintain the Facility and systems of treatment and control (and related appurtenances) that are installed and used by the Licensee to achieve compliance with the Conditions of this certification, and are 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 and when required by Department rules.

2. In the event of a prolonged [thirty (30) days or more] equipment malfunction or shutdown of pollution control equipment, operation may be allowed to resume and continue to take place under an appropriate Department order, provided that the Licensee demonstrates that such operation will be in compliance with all applicable ambient air quality standards and PSD increments, solid waste rules, domestic wastewater rules and industrial wastewater rules. During such malfunction or shutdown, the operation of the TCEC facility shall comply with all other requirements of this certification and all applicable state and federal emission and effluent standards not affected by the malfunction or shutdown which is the subject of the Department's order.

3. Licensee shall comply with the terms and conditions contained in Permit No. PSD-FL- 353, when issued, and any revisions, modifications or reissuances thereof.

B. Non-Compliance Notification

If, for any reason, the Licensee (defined as the applicant or its successors and/or assigns) does not comply with or will be unable to comply with any limitation specified in this certification, the Licensee shall notify the Southeast District office of the DEP by telephone at (561) 681-6600. After normal business hours, reports of any condition that poses a public health threat shall be made to the State Warning Point at telephone number (850) 413-9911 or (850) 413-9912. The Licensee shall confirm this non-compliance in writing at the DEP Southeast District Office, 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401 within seventy-two (72) hours of becoming aware of such conditions, and shall supply the following information

1. A description of the discharge and cause of noncompliance; and,

2. The period of non compliance, including exact 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 noncomplying event.

C. Spill Notification

1. The Licensee shall report all critical (having potential to significantly pollute surface or ground waters) spills of liquid or liquid-solid materials, not confined to a building or similar containment structure, to the Department by telephone immediately after discovery and submit a written report within forty eight hours, excluding weekends, from the original notification. The telephonic report shall be submitted by calling the Southeast District Industrial Wastewater Compliance/Enforcement Section under telephone number (561) 681-6600. After normal business hours, contact the State Warning Point by calling (850) 413-9911 or (850) 413-9912. The written report shall include, but not be limited to, a detailed description of how the spill occurred, the name and chemical make-up (include any MSDS sheets) of the substance, the amount spilled, the time and date of the spill, the name and title of the person who first reported the spill, the areal size of the spill and surface types (impervious, ground, water bodies, etc.) it impacted, the cleanup procedures used and status of completion, and include a map or aerial photograph showing the extent and paths of the material flow. Any deviation from this requirement must receive prior approval from the Department.

2. For unauthorized releases or spills of untreated or treated wastewater that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the Department by calling the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the Licensee becomes aware of the discharge. The Licensee, to the extent known, shall provide the following information to the State Warning Point:

a. Name, address, and telephone number of person reporting;

b. Name, address, and telephone number of licensee or responsible person for the discharge;

c. Date and time of the discharge and status of discharge (ongoing or ceased);

d. Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);

e. Estimated amount of the discharge;

f. Location or address of the discharge;

g. Source and cause of the discharge;

h. Whether the discharge was contained on-site, and cleanup actions taken to date;

i. Description of area affected by the discharge, including name of water body affected, if any; and

j. Other persons or agencies contacted.

D. Safety

1. The overall design, layout, and operation of the Facility shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards and any applicable Florida occupational safety standards will be complied with during construction.

2. The Licensee shall not discharge to surface waters wastes which are acutely toxic, or present in concentrations which are carcinogenic, mutagenic, or teratogenic to human beings or to significant locally occurring wildlife or aquatic species. The Licensee shall not discharge to ground waters wastes in concentrations which, alone or in combination with other substances, or components of discharges (whether thermal or non-thermal) are carcinogenic, mutagenic, teratogenic, or toxic to human beings (unless specific criteria are established for such components in Section 62-520.420, F.A.C.) or are acutely toxic to indigenous species of significance to the aquatic community within surface waters affected by the ground water at the point of contact with surface waters.

E. Enforcement

The Department may take any and all lawful actions as it deems appropriate to enforce any condition of this certification.

F. Design and Performance Criteria

The power plant may be operated at up to the maximum electrical output projected from design information without the need for modifying these Conditions. Treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this certification are not to be bypassed without prior DEP approval. Moreover, the Licensee shall take all reasonable steps to minimize any adverse impacts resulting from noncompliance with any limitation specified in this certification, including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying event.

G. Certification - General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in these Conditions of certification are the same as "Permit Conditions" and are

binding and enforceable pursuant to Sections 403.141, 403.161, 403.514, 403.727, and 403.859 through 403.861, F.S. Any noncompliance with a condition of certification or condition of a federally delegated or approved permit constitutes a violation of chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. The Licensee is placed on notice that the Department will review this approval periodically and may initiate enforcement action for any violation of these Conditions.

2. This approval 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 Certification may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(7), 403.511, and 403.722(5), F.S., the issuance of this approval does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This approval is not a waiver of or approval of any other Department approval that may be required for other aspects of the Facility under federally delegated programs which are not addressed in this certification.

4. This certification does not relieve the Licensee 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 Facility, or from penalties therefore; nor does it allow the Licensee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The Licensee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of these Conditions which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a Licensee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with these Conditions.

5. In accepting this certification, the Licensee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this Facility which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the Facility arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

6. This certification is transferable only upon Department approval in accordance with Section 403.516, F.S., Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The Licensee shall be liable for any noncompliance of the approved activity until the transfer is approved by the Department.

7. These Conditions of certification or a copy thereof shall be kept at the work site of the approved activity.

8. The Licensee shall comply with the following:

a. Upon request, the Licensee 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 Licensee shall hold at the Facility or other location designated by these Conditions records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by these Conditions, copies of all reports required by these Conditions, and records of all data used to complete the Application. These materials shall be retained at least three (3) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule. Data utilized to prepare the Application may be maintained at the following locations:

Florida Municipal Power Agency

8553 Commodity Circle

Orlando, FL 32819-7767

or

Treasure Coast Energy Center

(Address to be provided upon commencement of construction)

Fort Pierce, Florida

c. Records of monitoring information shall include:

i. the date, exact place, and time of sampling or measurements;

ii. the person responsible for performing the sampling or measurements;

iii. the dates analyses were performed;

iv. the person responsible for performing the analyses;

v. the analytical techniques or methods used;

vi. the results of such analyses.

9. These Conditions may be modified, revoked and reissued, or terminated for cause. The filing of a request by the Licensee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

10. The Licensee, by accepting these Conditions, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

a. Enter upon the Licensee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under these Conditions;

b. Have access to and copy any records that shall be kept under the these Conditions;

c. Inspect the facilities, equipment, practices, or operations regulated or required under these Conditions; and

d. Sample or monitor any substances or parameters at any location necessary to assure compliance with these Conditions or Department rules.

11. When requested by the Department, the Licensee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating these Conditions, or to determine compliance with the Conditions. The Licensee shall also provide to the Department upon request copies of records required by these Conditions to be kept. If the Licensee becomes aware of relevant facts that were not submitted or were incorrect in the Application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department.

12. Unless specifically stated otherwise in Department rules, the Licensee, in accepting these Conditions, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the Licensee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard.

13. The Licensee, in accepting these Conditions, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C.

14. The Licensee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment.

15. The Licensee shall apply for a revision to any Department issued PSD, Title V, or NPDES permit in accordance with Department Rules in Chapter 62, Florida Administrative Code, and receive approval before construction of any planned substantial modifications to the certified Facility is to commence or in accordance with applicable rules for minor modifications to the certified Facility. A revised permit shall be obtained before construction begins except as provided in the applicable portions of Chapter 62, F.A.C.

16. The Licensee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with these Conditions. The Licensee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of these Conditions. The notice shall include the following information:

a. A description of the anticipated noncompliance;

b. The period of the anticipated noncompliance, including dates and times; and

c. Steps being taken to prevent future occurrence of the noncompliance.

17. Water quality sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.

a. Monitoring results shall be reported at the intervals specified elsewhere in these Conditions and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).

b. If the Licensee monitors any contaminant more frequently than required by these Conditions, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in these Conditions.

d. Under Chapter 62-160, F.A.C., sample collection shall be performed by following the protocols approved by the Department. Alternatively, sample collection may be performed by an organization that has an approved Comprehensive Quality Assurance Plan (CompQAP) on file with the Department. This CompQAP shall be approved for collection of samples from the required matrices and for the required tests.

18. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in these Conditions shall be submitted no later than 14 days following each schedule date. When requested by the Department, the Licensee shall within a reasonable time furnish any information required by applicable law, which is needed to determine compliance with the certification. If the Licensee becomes aware that relevant facts were not submitted or were incorrect in the Application or in any report to the Department, such facts or information shall be corrected promptly.

H. Laboratories and Quality Assurance

1. The Licensee shall ensure that all laboratory analytical data submitted to the Department, as required by this certification, must be from a laboratory which has a currently valid and Department approved Comprehensive Quality Assurance Plan (CompQAP) [or a CompQAP pending approval] for all parameters being reported, as required by Chapter 62-160, F.A.C.

2. When a contract laboratory is used to analyze samples required pursuant to this certification, the Licensee is required to have the samples taken by qualified personnel following EPA and Department approved sampling procedures and chain-of-custody requirements in accordance with Rule 62-160, F.A.C.

3. When an in-house laboratory is used to analyze samples required pursuant to these Conditions, the Licensee is required to have the samples taken by a qualified technician following EPA and Department approved sampling procedures and chain-of-custody requirements. All chain-of-custody records must be retained on-site for at least three (3) years and made available to the Department immediately upon request.

I. Procedures for Post-Certification Submittals

1. Purpose of Submittals

Conditions of certification which provide for the post-certification submittal of information to DEP by the Licensee are for the purpose of facilitating DEP's monitoring of the effects from the construction and maintenance of the Facility. This monitoring is for DEP to assure, in consultation with other agencies with applicable regulatory jurisdiction, continued compliance with these Conditions, without any further agency action.

2. Filings

All post-certification submittals of information by the Licensee are to be filed with DEP. Copies of each submittal shall be simultaneously submitted to any other agency indicated in the specific Conditions requiring the post-certification submittals.

3. Completeness

The DEP shall promptly review each post-certification submittal for completeness. This review shall include consultation with the other agencies receiving the post-certification submittal. For the purposes of this condition, completeness shall mean that the information submitted is both complete and sufficient. If found to be incomplete, the Licensee shall be so notified. Failure to issue such a notice within forty-five (45) days after filing of the submittal shall constitute a finding of completeness.

4. Interagency Meetings

Within sixty (60) days of the filing of a complete post-certification submittal, DEP may conduct an interagency meeting with other agencies which received copies of the submittal. The purpose of such an interagency meeting shall be for the agencies with regulatory jurisdiction over the matters addressed in the post-certification submittal to discuss whether reasonable assurance of compliance with these Conditions has been provided. Failure of any agency to attend an interagency meeting shall not be grounds for DEP to withhold a determination of compliance with these Conditions nor to delay the time frames for review established by these Conditions.

5. Reasonable Assurance of Compliance

Within ninety (90) days of the filing of a complete post-certification submittal, or 45 days after a submittal is made by the Licensee, or unless another date is specified herein, DEP shall give written notification to the Licensee and the agencies to which the post-certification information was submitted of its determination whether there is reasonable assurance of compliance with these Conditions. If it is determined that reasonable assurance has not been provided, the Licensee shall be notified with particularity and possible corrective measures suggested. Failure to notify the Licensee in writing within ninety (90) days of receipt of a complete post-certification submittal shall constitute a compliance determination.

6. Commencement of Construction

If DEP does not object within the time period specified in Condition III.I.5. above, the Licensee may begin construction pursuant to the terms of the Conditions of certification and the subsequently submitted construction details.

IV. ADVERSE IMPACT

The Licensee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge. The Licensee shall not adversely impact any jurisdictional wetland without prior approval.

V. RIGHT OF ENTRY

The Licensee shall allow during normal business hours the Secretary of the Florida Department of Environmental Protection and/or authorized representatives, including representatives of the SFWMD upon the presentation of credentials:

A. To enter upon the Licensee's Facility where an emission or effluent source is located or in which records are required to be kept under the terms and Conditions of this certification;

B. To have access during normal business hours (Monday - Friday, 9:00 a.m. to 4:00 p.m.) to any records required to be kept under these Conditions for examination and copying;

C. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants, or monitor any substances or parameters at any location reasonably necessary to assure compliance with these Conditions or Department rules; and,

D. To assess any damage to the environment or violation of ambient standards.

VI. REVOCATION OR SUSPENSION

This certification may be suspended or revoked for violations of any of these Conditions pursuant to Section 403.512, F.S.

VII. CIVIL AND CRIMINAL LIABILITY

This certification does not relieve the Licensee from civil or criminal penalties for noncompliance with any Conditions of this certification, applicable rules or regulations of the Department or Chapter 403, F.S., or regulations there-under. Subject to Section 403.511, F.S., this certification shall not preclude the institution of any legal action or relieve the Licensee from any responsibilities or penalties established pursuant to any other applicable state statutes or regulations.

VIII. PROPERTY RIGHTS

The issuance of this certification does not convey any property rights in either real or personal property, nor any exclusive privileges, nor 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 certification 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.

IX. SEVERABILITY

The provisions of this certification are severable, and if any provision of this certification or the application of any provision of this certification to any circumstances is held invalid, the application of such provisions to other circumstances and the remainder of the certification shall not be affected thereby.

X. REVIEW OF SITE CERTIFICATION

The certification shall be final unless revised, revoked, or suspended pursuant to law. At least every five (5) years from the date of issuance of certification the Department may review these Conditions and propose any needed changes.

XI. MODIFICATION OF CONDITIONS

A. Pursuant to Subsection 403.516(1), F.S., the Siting Board hereby delegates the authority to the Department to modify any condition of this certification, except that any proposed modification to burn a fuel other than natural gas or distillate oil shall be reviewed by the Board.

B. Subject to the notice requirements of 403.516(1), F.S., the certification may be modified to conform to subsequent DEP-issued amendments, modifications or renewals of any separately-issued Prevention of Significant Deterioration (PSD) permit, Title V Air Operation permit, or National Pollutant Discharge Elimination System (NPDES) permit for the Facility and the conditions of such permits shall be controlling over these Conditions.

XII. CONSTRUCTION

A. Standards and Review of Plans

1. The Project shall be constructed pursuant to the design standards presented in the Application and the standards or plans and drawings submitted and signed by an engineer registered in the state of Florida. Specific Southeast District office acceptance of plans will be required based upon a determination of consistency with approved design concepts, regulations and these Conditions, prior to initiation of construction if the Licensee proposes to construct any new: industrial waste treatment facilities; domestic waste treatment facilities; potable water treatment and supply systems; ground water monitoring systems and storm water runoff systems; solid waste disposal areas; facilities impacting jurisdictional wetlands, and hazardous or toxic handling facilities or areas. The Licensee shall present specific facility plans for these types of facilities for review by the Southeast District office at least ninety (90) days prior to construction of those portions of the Facility for which the plans are then being submitted, unless other time limits are specified in the Conditions herein. Review and approval or disapproval shall be accomplished in accordance with Chapter 120, F.S., or these Conditions as applicable.

2. The Department must be notified in writing and prior written approval obtained for any changes, modification, or revision to be made to the project during construction which is in conflict with these Conditions. If there are any changes, modification, or revision made to the Project as certified without this prior written approval, the project will be considered to have been constructed without departmental approval, the construction will not be cleared for service, and the construction will be considered a violation of these Conditions.

3. Ninety (90) days prior to the anticipated date of first operation, the Licensee shall provide the Department with an itemized list of any changes made to the facility design and operation plans that would affect a change in discharge as referenced in Condition II herein, after issuance of these Conditions. This post certification review of the final design and operation shall demonstrate continued compliance with Department rules and standards.

B. Control Measures

1. Storm Water Runoff

To control runoff during construction which may reach and thereby pollute waters of the state, necessary measures shall be utilized to settle, filter, treat or absorb silt-containing or pollutant-laden storm water to ensure against spillage or discharge of excavated material that may cause turbidity in excess of 29 Nephelometric Turbidity Units above background in waters of the state. Control measures may consist of sediment traps, barriers, berms, and vegetation plantings. Exposed or disturbed soil shall be protected and stabilized as soon as possible to minimize silt and sediment-laden runoff. The pH of the runoff shall be kept within the range of 6.0 to 8.5.

2. Open Burning

Any open burning in connection with initial land clearing shall be in accordance with Chapter 62-256, F.A.C., Chapter 5I-2, F.A.C., and any applicable county regulation. Any burning of construction-generated material, after initial land clearing, that is allowed to be burned in accordance with Chapter 62-256, F.A.C., shall be approved by the Southeast District office in conjunction with the Division of Forestry and other county regulations that may apply. Burning shall not occur unless approved by the appropriate agency. Burning shall also not occur if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.

3. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the appropriate local health agency.

4. Solid Wastes

Solid wastes resulting from construction shall be disposed of in accordance with the applicable regulations of Chapter 62-701, F.A.C. Solid wastes generated during operation shall be disposed of off-site in DEP licensed facilities by licensed contractors.

5. Noise

Construction noise shall not exceed noise requirements of the St. Lucie County Noise Ordinance.

6. Dust and Odors

The Licensee shall employ proper odor and dust control techniques to minimize odor and fugitive dust emissions. The Licensee shall employ control techniques sufficient to prevent nuisance conditions on adjoining property.

7. Transmission Lines

Any directly associated transmission lines from the FMPA/TCEC electric switchyard to the existing Florida Power and Light company transmission system shall be maintained in accordance with the Application and the appropriate state and federal regulations concerning use of herbicides. The Licensee shall notify the Southeast District office of the Department of the type of herbicide to be used at least 60 days prior to its first use.

8. Dewatering Operations

Any dewatering operations during construction shall be carried out in accordance with the applicable provisions of Rule 62-621.300(2), F.A.C.

9. Historical or Archaeological Finds

If historical or archaeological artifacts, such as Indian canoes, are discovered at any time within the project site, the Licensee shall notify the DEP Southeast District office and the Bureau of Historic Preservation, Division of Historical Resources, R. A. Gray Building, Tallahassee, Florida 32399-0250, telephone number (850) 487-2073.

C. Environmental Control Program

The Licensee shall appoint a representative to conduct an environmental control program. Such representative shall be under the supervision of a Florida registered professional engineer or other qualified person and shall assure that all construction activities conform to applicable environmental regulations and these Conditions. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the Application or the evidence presented at the certification hearing is detected during construction, the Licensee shall notify the Southeast District office as required by Condition III.B.

D. Reporting

Notice of commencement of construction on the Project shall be submitted to the Siting Coordination Office and the Southeast District office within fifteen (15) days of initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the Southeast District Office 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401. The report shall be a short narrative describing the progress of construction.

XIII. AIR

A. General and Administrative Requirements

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Mail Station 5505, Tallahassee, Florida 32399-2400 and telephone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Southeast District Office, 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401.

2. The terms, conditions, requirements, limitations, and restrictions set forth in draft Permit PSD-FL-353, and any final issuance, modification, or amendment to such PSD permit, are incorporated by reference herein, and are binding and enforceable Conditions of this Certification. The Licensee is subject to and shall comply with the terms, conditions, requirements, limitations, and restrictions set forth in Attachment A. A violation of the terms conditions, requirements, limitations, and restrictions in Attachment A is a violation of these Conditions of Certification.

3. The Department is delegated the authority to modify these Conditions of Certification to conform them to any subsequently issued amendment or modification to Permit No. PSD-FL-353, pursuant to Conditions XI.A and B, above.

B. Emission Units

This section of the Conditions addresses the following emissions units:

EU ID No.	Emission Unit Description
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

C. PERMITTING AUTHORITY

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

D. Compliance Authority

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Southeast District, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401.

E. Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7) (b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards for Subpart Da, Subpart GG, and Subpart KKKK (as proposed). Some separate reporting and monitoring may be required by the individual subparts.

a. Subpart A, General Provisions, 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

40 CFR 60.19, General Notification and Reporting Requirements

b. Subpart Da, Standards of Performance for Electric Utility Steam Generating Units These provisions include standards for duct burners.

c. Subpart GG, Standards of Performance for Stationary Gas Turbines: These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

d. Subpart KKKK, Standards of Performance for Stationary Gas Turbines: These provisions were published February 18, 2005 as a proposed new NSPS standard. The final rule may be applicable to Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

Equipment

3. Gas Turbine: The licensee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 170 MW. The gas turbine will be equipped with DLN combustors, and an inlet air filtration system with evaporative coolers. The unit shall include the Speedtronic™ Mark VI automated gas turbine control system, and will have dual-fuel capability. [Application; Design]

4. HRSG: The licensee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 565.3 MMBtu per hour (HHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. [Application; Design]

Control Technology

5. DLN Combustion: The licensee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

6. Water Injection: The licensee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for the gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

7. Selective Catalytic Reduction (SCR) System: The licensee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical,

piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

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

Performance Restrictions

8. Permitted Capacity – Gas Turbine: The maximum heat input rate to the gas turbine is 1,787 MMBtu per hour when firing natural gas and 1,986 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The licensee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

9. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for the HRSG is 565.3 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

10. Hours of Operation: The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

11. Authorized Fuels: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. The gas turbine shall fire no more than 500 hours of fuel oil, regardless of mode, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

12. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

a. Combined Cycle Operation: The gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

b. Pseudo Simple Cycle Operation: The gas turbine/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

c. Inlet Fogging: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."

d. Duct Firing: The HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

[Application; Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

13. Emissions Standards

Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT) CT & Duct Burner (DB)	8.0 8.0	37.8 47.3	8.0, 24-hr
	Gas	CT, Normal	4.1	16.2	
		CT & Duct Burner (DB)	7.6	39.1	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month

NO_X [b]	Oil	CT	8.0	62.0	8.0, 24-hr
		CT & DB	8.0	78.0	
	Gas	CT, Normal	2.0	13.1	2.0, 24-hr
		CT & DB	2.0	16.9	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, established in Condition No. 11 of this section, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be determined by the requirements in Condition No. XIII.E.30 of this section. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, established in Condition No. XIII.E.11 this section, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. XIII.E.0 of this section.

e. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

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

Excess Emissions

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. XIII.E.13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

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

15. Definitions

a. Startup is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

b. Shutdown is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]

c. Malfunction is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

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

17. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

18. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. Steam Turbine/HRSG System Cold Startup: For cold startup of the steam turbine/HRSG system, excess emissions from the gas turbine/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue}

b. Steam Turbine/HRSG System Warm Startup: For warm startup of the steam turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. Shutdown: For shutdown of the combined cycle operation, excess emissions from the gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

d. Fuel Switching: Excess emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbine/HRSG system including the pollution control equipment. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the licensee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

Emissions Performance Testing

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Determinations: The gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. The unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. The Department may, for good reason, require the licensee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a) and (b), F.A.C. and 40 CFR 60.8]

23. Annual Compliance Tests: During each federal fiscal year (October 1^{st}, to September 30^{th}), the gas turbine shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7) (a) 4, F.A.C.]

24. Continuous Compliance: The licensee shall demonstrate continuous compliance with the 24-hour CO and NOX emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the licensee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. [Rule 62-212.400 (BACT), F.A.C.]

Continuous Monitoring Requirements

25. CEM Systems: The licensee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the licensee shall notify the Compliance Authority.

CO Monitor: The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

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

Diluent Monitor: The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

Data Collection: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

Valid Hour: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The licensee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. 24-hour Block Averages: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages*: Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

e. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. XIII.E.18 and 20 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The licensee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the licensee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The licensee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a) (5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

Records and Reports

28. Monitoring of Capacity: The licensee shall monitor and record the operating rate of the gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the licensee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation,

hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by sampling and analysis of the fuel by the licensee or vendor for sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each fuel delivery, the licensee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or from an analysis conducted by the licensee, in accordance with the above methods. At the request of a Compliance Authority, the licensee shall perform additional sampling and analysis for the fuel sulfur content.

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

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8) (c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.]

32. Excess Emissions Reporting:

a. Malfunction Notification: If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the licensee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the licensee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. NSPS Semi-Annual Reports: For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. Within thirty (30) days following each calendar semi-annual period, the licensee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority. This also includes reporting any periods of excess emissions as applicable and defined by NSPS Subpart KKKK when the rule is finalized.

{Note: If there are no periods of excess emissions as defined in NSPS Subparts GG, Da, or KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.} *[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j) (1)]*

33. <u>Annual Operating Report</u>: The licensee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The licensee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

F. Fuel Oil Storage Tank (EU 002)

ID	Emission Unit Description
002	One distillate fuel oil storage tank for Unit 1 combustion turbine (approximately 1 million gallons).

NSPS Applicability

1. NSPS Subpart Kb Applicability: Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 5.2 kPa and greater than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the monitoring requirements. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. The fuel oil storage tank (EU 002) has a capacity greater than 151 cubic meters and the vapor pressure of the ultra low sulfur fuel oil is less than 3.5 kPa, therefore NSPS Kb, including the monitoring requirements, does not apply to this unit. [40 CFR 60.110b (a) and (b), and 60.116b(c); Rule 62-204.800(7) (b), F.A.C.]

Equipment Specifications

2. Equipment: The licensee is authorized to install, operate, and maintain one 990,000 gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 1 gas turbine. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

Performance Requirements

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year).
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

Notification, Reporting, and Records

4. Oil Tank Records: The licensee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The licensee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for use in the Annual Operating Report.
[Rule 62-204.800(7) (b)16, F.A.C.]

G. Cooling Tower (EU 003)

ID	Emission Unit Description
003	One 8-cell mechanical draft cooling tower.

Equipment

1. Cooling Tower: The licensee is authorized to install one 8-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 111,130 gpm; a design air flow rate of 1,000,000 acfm per cell; drift eliminators; a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

Emissions and Performance Requirements

Drift Rate: Within 60 days of commencing commercial operation, the licensee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 10 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}H. Safe shutdown Generator (EU004)

H. Safe Shutdown Generator (EU004)

ID	Emission Unit Description
004	One safe shutdown generator (approximately 1525 hp) with associated 1000 gallon fuel oil storage tank.

NESHAPS Applicability

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

NSPS Applicability

NSPS Subpart IIII Applicability: The emergency generator is a Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and may be subject to 40 CFR 60, Subpart IIII at the time the proposed rule becomes final.

The emergency generator shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations.

[40 CFR 60, NSPS-Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Proposed Rule- Federal Register / Vol. 70, No. 131 / July 11, 2005. Pages 39869 – 39904].

Equipment Specifications

1. Safe Shutdown Generator: The licensee is authorized to install, operate, and maintain one safe shutdown generator. The safe shutdown generator may operate when the transmission connection is lost and the plant shuts down, and during occasional testing to ensure operability. The safe shutdown generator will fire ULS fuel oil. [Application; Design]

Emissions and Performance Requirements

2. Hours of Operation: The safe shutdown generator may operate 200 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

I. Diesel Fire Pump

ID	Emission Unit Description
005	One diesel engine fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank.

NESHAPS Applicability

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

Equipment Specifications

1. Fire Pump: The licensee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank. The diesel engine fire pump will fire ULS fuel oil. [Application; Design]

Emissions and Performance Requirements

2. Hours of Operation: The fire pump may operate 200 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.

{Permitting Note: The fire pump is considered emergency equipment, therefore exempt from permitting, however its emissions are included in the potential to emit for the project.

XIV. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

This facility does not discharge to surface waters of the State.

B. Underground Injection Control Systems

This section is not applicable to this facility.

C. Land Application Systems

This section is not applicable to this facility.

D. Other Methods of Disposal or Recycling

There shall be no discharge of industrial wastewater from this facility to ground or surface waters, except as authorized by these Conditions. Cooling tower blowdown may not be discharged to the Fort Pierce Utilities Authority's deep well injection system until at least one such well is in full operation.

E. Other Limitations and Monitoring and Reporting Requirements

1. During the period of operation authorized by these Conditions, the Licensee shall complete and submit to the Southeast District Office Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e., monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DEP's DMR forms (available at the Southeast District Office). Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type On DMR	Monitoring Period	DMR Due Date
Monthly or Toxicity	First day of month – last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge.

1. The Licensee shall make copies of the attached DMR form(s) and shall submit the completed DMR form(s) to the Department's Southeast District Office at the address specified in Permit Condition XIV.E.2. below.

2. Unless specified otherwise in these Conditions, all reports and notifications required by these Conditions, including twenty-four hour notifications, concerning the Facility's percolation pond system shall be submitted to or reported to the South District Office at the address specified below:

Southeast District Office

400 North Congress Avenue, Suite 200,

West Palm Beach, FL 33401

Phone Number - (561) 681-6600

FAX Number - 561.681.6755

(All FAX copies shall be followed by original copies.)

3. The Licensee shall provide safe access points for obtaining representative effluent and stormwater samples, which are required by these Conditions.

4. If there is no discharge from the Facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

F. Industrial Sludge Management Requirements

This section not applicable to this facility.

G. Ground Water Monitoring Requirements

This section not applicable to this facility.

H. Record keeping Requirements:

1. The Licensee shall maintain the following records on the site of the permitted Facility and make them available for inspection:

a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

b. Copies of all reports, other than those required in items a. and f. of this Condition, required by the certification for at least three years from the date the report was prepared, unless otherwise specified by Department rule;

c. Records of all data, including reports and documents used to complete the Application for the certification for at least three years from the date the application was filed, unless otherwise specified by Department rule;

d. A copy of the current certification;

e. A copy of any required record drawings;

f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

I. Other Specific Conditions

1. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under these Conditions, shall be signed and sealed by the professional(s) who prepared them.

2. Section XIV. of these Conditions addresses Industrial Wastewater program permitting requirements only and does not authorize operation of this Facility prior to obtaining any other permits required by federal agencies.

3. Specific Conditions Related to Construction

a. Within thirty days of completion of construction of any new industrial wastewater facilities, the Licensee shall submit to the Department a completed "Certification of Completion of Construction" (DEP Form 62-620.910(12)) signed and sealed by the engineer of record or other engineer registered in the state of Florida.

b. Record drawings of any new industrial wastewater facilities shall be prepared and made available in accordance with Rule 62-620.410(6), F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting within six months of placing such facilities into operation.

4. Reopener Clause

a. The applicable Conditions in Section XIV. of this certification shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

i. Contains different conditions or is otherwise more stringent than the Conditions in this certification/or;

ii. Controls any pollutant not addressed in these Conditions of Certification.

iii. The Conditions of Certification as revised or reissued under this subsection shall contain any other requirements then applicable.

b. These Conditions may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, or other information show a need for a different limitation or monitoring requirement.

c. The Department may develop an applicable Total Maximum Daily Load (TMDL) during the life of this certification. Once a TMDL has been established and adopted by rule, the Department shall revise these Conditions to incorporate the final findings of the TMDL.

5. Notice of Modification or Revision

The Licensee shall file an amendment or apply for a modification to this Certification in accordance with Rules 62-620.300 and the Department of Environmental Protection Guide to Wastewater Permitting at least 90 days before construction of any planned substantial modifications to the Facility's wastewater system or with Rule 62-620.325(2) for minor modifications to the Facility's wastewater system. A revised Condition or the Department's concurrence shall be obtained before construction begins on such modifications to the wastewater systems, except as provided in Rule 62-620.300, F.A.C. [62-620.610(16), F.A.C.]

6. Any laboratory test required by these Conditions shall be performed by a laboratory that has been certified by the Department of Health (DOH) under Chapter 64E-1, F.A.C., where such certification is required by Rule 62-160.300, F.A.C. The laboratory must be certified for any specific method and analyte combination that is used to comply with these Conditions. For domestic wastewater facilities, the on-site test procedures specified in Rule 62-160.300(4), F.A.C., shall be performed by a laboratory certified test for those parameters or under the direction of an operator certified under Chapter 62-602, F.A.C.

7. Field activities including on-site tests and sample collection, whether performed by a laboratory or a certified operator, must follow the applicable procedures described in DEP-SOP-001/01 (January 2002). Alternate field procedures and laboratory methods may be used where they have been approved according to the requirements of Rules 62-160.220, 62-160.330, and 62-160.600, F.A.C.

8. Bypass Provisions

a. Bypass is prohibited, and the Department may take enforcement action against a Licensee for bypass, unless the Licensee affirmatively demonstrates that:

i. Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

ii. There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance; and

iii. The Licensee submitted notices as required under Condition III.B.

b. If the Licensee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The Licensee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition XIV.K.7.a. of these Conditions. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the Licensee demonstrates that it will meet the three conditions listed in Condition XIV.K.7.a. of these Conditions.

i. A Licensee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition XIV.K.7.a. of these Conditions. [62-620.610(22), F.A.C.]

9. Upset Provisions:

a. A Licensee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:

i. An upset occurred and that the Licensee can identify the cause(s) of the upset;

ii. The permitted facility was at the time being properly operated;

iii. The Licensee submitted notice of the upset as required in Condition III. of these Conditions; and

iv. The Licensee complied with any remedial measures required under Condition III.G.4.

b. In any enforcement proceeding, the Licensee seeking to establish the occurrence of an upset has the burden of proof.

c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review. [62-620.610(23), F.A.C.]

XV. South Florida Water Management District

A. LEGAL/ADMINISTRATIVE CONDITIONS

1. GENERAL

a. Responsible Entity

The Licensee shall be responsible for compliance with the Certification Conditions. If contractual rights, duties, or obligations are transferred under this Certification, notice of such transfer or assignment, including the identification of the entity responsible for compliance with the Certification, shall immediately be submitted to the Florida Department of Environmental Protection and the SFWMD by the previous certification holder (Licensee) and the Assignee. Any assignment or transfer shall carry with it the full responsibility for the limitations and conditions of this Certification. The previous Licensee shall be responsible for informing the Assignee of all authorized facilities and uses and the conditions under which they were authorized. The previous Licensee shall remain liable for corrective actions that may be required as a result of any violations prior to transfer or assignment of any contractual rights, duties, or obligations under this Certification. Reference: Sections 373.223, 373.342, and 373.413, F.S.; Rules 40E-2.091, 40E-2.301, 40E-2.381, and 40E-3.101(1), F.A.C.

b. Minimum Standards

This Certification is based on the Licensee's submitted information to the SFWMD which reasonably demonstrates that harm to the site water resources will not be caused by the authorized activities. The plans, drawings and design specifications submitted by the Licensee shall be considered the minimum standards for compliance. Reference: Sections 373.219, 373.223, 373.229, 373.308, and 373.316, F.S.; Rules 40E-2.091, 40E-2.301, 40E-2.381, and 40E-3.500-531, F.A.C.

c. Compliance Requirements

This project must be constructed, operated and maintained in compliance with and meet all non-procedural requirements set forth in Chapter 373, F.S., and Chapters 40E-2 (Consumptive Use), 40E-3 (Water Wells), and 40E-20 (General Water Use Permits), F.A.C.

d. Off-site Impacts

It is the responsibility of the Licensee to ensure that harm to the water resources does not occur during the construction, operation, and maintenance of the project. Reference: Sections 373.223 and 373.309, F.S.; Rules 40E-2.091, 40E-2.381, 40E-3.301(3), and 40E-3.301(4), F.A.C.

e. Liability

The Licensee shall hold and save the SFWMD harmless from any and all damages, claims, or liabilities which may arise by reason of the construction, alteration, operation, maintenance, removal, abandonment and/or use of any system authorized by this Certification, to the extent allowed under Florida law. Reference: Section 373.223, F.S.; Rules 40E-2.091, and 40E-2.381, F.A.C.

f. Construction, Operation, and Maintenance Responsibilities

The Licensee shall be responsible for the construction, operation, and maintenance of all facilities installed for the proposed project. Reference: Section 373.309, F.S.; Rule 40E-3.301, F.A.C.

g. Access

SFWMD representatives shall be allowed reasonable escorted access to the power plant site, the water withdrawal facilities and any associated facilities to inspect and observe any activities associated with the construction of the proposed project and/or the operation and/or maintenance of the on-site wells in order to determine compliance with the conditions of this Certification. The Licensee shall not refuse entry or access to any SFWMD representative who, upon reasonable notice, requests entry for the purpose of the above noted inspection and presents appropriate credentials. Reference: Sections 373.223 and 373.319, F.S.; Rules 40E-2.091, 40E-2.301, 40E¬-2.381, and 40E-3.461, F.A.C.

h. Post Certification Information Submittals

Information submitted to the SFWMD subsequent to Certification, in compliance with the conditions of this Certification, shall be for the purpose of the SFWMD determining the Licensee's compliance with the Certification conditions and the non-procedural criteria contained in Chapters 40E-2, 40E-3, and 40E-20, F.A.C., as applicable, prior to the commencement of the subject construction, operation and/or maintenance activity. Reference: Rule 62-17.191, F.A.C.

i. Enforcement

The SFWMD may take any and all lawful actions that are necessary to enforce any condition of this Certification based on the authorizing statutes and rules of the SFWMD. Prior to initiating such action, the SFWMD shall notify the Secretary of DEP of the proposed action. Reference: Sections 373.223 and 373.319, F.S.; Rules 40E-2.091, 40E-2.301, 40E-¬2.381, and 40E-3.461, F.A.C.

2. PROCESSING OF INFORMATIONAL REQUESTS

a. Completeness and Sufficiency Review

At least ninety (90) days prior to the commencement of construction of any portion of the project, the Licensee shall submit to SFWMD staff, for a completeness and sufficiency review, any pertinent additional information required under the SFWMD's Conditions of Certification for that portion proposed for construction. If SFWMD staff does not issue a written request for additional information within thirty (30) days, the information shall be presumed to be complete and sufficient. Reference: Section 373.413(2), F.S.

b. Compliance Review and Confirmation

Within sixty (60) days of the determination by SFWMD staff that the additional information is complete and sufficient, the SFWMD shall determine and notify the Licensee in writing whether the proposed activities conform to SFWMD rules, as required by Chapters 40E-2, 40E-3, and 40E-20, F.A.C., and the Conditions of Certification. If necessary, the SFWMD shall identify what items remain to be addressed. No construction activities shall begin until the SFWMD has determined either in writing, or by failure to notify the Licensee in writing, that the activities are in compliance with the applicable SFWMD criteria. Reference: Sections 373.413(1) and (2), F.S.

c. Revisions to Site Specific Design Authorizations

The Licensee shall submit, consistent with the provisions of Condition A.2., any proposed revisions to the site specific design authorizations specified in this Certification to the SFWMD for review and approval prior to implementation. The submittal shall include all the information necessary to support the proposed request, including detailed drawings, calculations and/or any other applicable data. Such requests may be included as part of the appropriate additional information submittals required by this Certification provided they are clearly identified as a requested modification to the previously authorized design. Reference: Sections 373.219, 373.223, 373.313, F.S.; Rules 40E-2.091, 40E-2.301, and 40E-3.461, F.A.C.

d. Dispute Resolution

Since this Certification is the only form of permit required from any agency, it is understood that the Licensee and the SFWMD shall strive to resolve disputes by mutual agreement. Reference: Sections 373.413 and 373.429, F.S.; Rules 40E-1.601 and 40E-4.331, F.A.C.

e. Objections

Objections to modifications of the terms and conditions of this Certification shall be resolved through the process established in Section 403.516, F.S.

f. Changes to Information Requirements

The SFWMD and the Licensee may jointly agree to vary the informational requirements. Reference: Sections 373.085 and 373.229, F.S.; Rules 40E-2.101(1) and 40E-3.101(2), F.A.C.

B. WATER USE CONDITIONS

1. GENERAL

a. Water Shortage Compliance

In the event of a declared water shortage, the Licensee must comply with any water withdrawal reductions ordered by the SFWMD in accordance with the Water Shortage Plan, Chapter 40E-21, F.A.C. Reference: Section 373.246, F.S.; Rule 40E-2.381, F.A.C.

b. Interference with Existing Legal Uses

The Licensee shall mitigate interference with legal uses existing at the time certification was issued by the Siting Board that was caused in whole or in part by the Licensee's withdrawals, consistent with an approved mitigation plan. As necessary to offset the interference, mitigation may include pumpage reduction, replacement of the impacted individual's equipment, relocation of wells, change in withdrawal source, or other means. Interference to an existing legal use is defined as an impact that occurs under hydrologic conditions equal to or less severe than a 1 in 10 year drought event that results in the:

(1) Inability to draw water consistent with the provisions of the permit, such as when remedial structural or operational actions not materially authorized by existing permits must be taken to address the interference;

(2) Change in the quality of water pursuant to primary State Drinking Water Standards to the extent that the water can no longer be used for its authorized purpose, or such change is imminent; or

(3) Inability of an existing legal user to meet its permitted demands without exceeding the permitted allocation.

Reference: Section 373.223, F.S.; Rules 40E-2.091, 40E-2.301, and 40E-2.381, F.A.C.

c. Harm to Existing Off-Site Land Uses

The Licensee shall mitigate harm to existing off-site land uses caused by the Licensee's withdrawals, as determined through reference to the conditions for permit issuance. When harm occurs, or is imminent, the SFWMD will require the Licensee to modify withdrawal rates or mitigate the harm. Harm, as determined through reference to these Conditions of Certification includes:

(1) Significant reduction in water levels on off-site property to the extent that the designed function of the water body and related surface water management improvements are damaged, not including aesthetic values. The designed function of a water body is identified in the original permit or other government authorization issued for the construction of the water body. In cases where a permit was not required, the designed function shall be determined based on the purpose for the original construction of the water body (e.g., fill for construction, mining, drainage canal, etc.);

(2) Damage to agriculture, including damage resulting from reduction in soil moisture resulting from consumptive use;

(3) Land collapse or subsidence caused by reduction in water levels associated with consumptive use.

Reference: Sections 373.223, F.S.; Rules 40E-2.091, 40E-2.301, and 40E-2.381, F.A.C.

d. Harm to Natural Resources

The Licensee shall mitigate harm to natural resources caused by the Licensee's withdrawals, as determined through reference to the SFWMD conditions for permit issuance. When harm occurs, or is imminent, the SFWMD will require the Licensee to modify withdrawal rates or mitigate the harm. Harm, as determined through reference to these Conditions of Certification includes:

(1) Reduction in ground or surface water levels that results in harmful lateral movement of the fresh water/salt water interface;

(2) Reduction in water levels that harm the hydroperiod of wetlands;

(3) Significant reduction in water levels or hydroperiod in a naturally occurring water body such as a lake or pond;

(4) Harmful movement of contaminants in violation of state water quality standards; or

(5) Harm to the natural system including damage to habitat for rare or endangered species.

Reference: Sections 373.223, F.S.; Rules 40E-2.091, 40E-2.301, and 40E-2.381, F.A.C.

e. Well System Operation

At any time, if there is an indication that the well casing, valves, or controls associated with the on-site well system leak or have become inoperative, the Licensee shall be responsible for making the necessary repairs or replacement to restore the well system to an operating condition that meets the criteria set forth in Chapter 40E-3, F.A.C. Failure to make such repairs shall be the cause for requiring that the well(s) be filled and abandoned in accordance with the procedures outlined in Chapter 40E-3, F.A.C. Reference: Sections 373.308 and 373.316, F.S.; Rules 40E-3.041, 40E-3.101, 40E-3.411, and 40E-3.500-531, F.A.C.

2. SITE SPECIFIC DESIGN AUTHORIZATIONS

a. Authorized Monthly Withdrawals

This Certification authorizes a maximum monthly withdrawal of 110.205 MGM from the Floridan aquifer for cooling tower makeup water, service water, and fire protection water for Unit #1 prior to the availability of reclaimed water from the Ft. Pierce Utility Authority. After use of reclaimed water has commenced, this Certification authorizes a maximum monthly withdrawal of 106.65 MGM from the Floridan aquifer for cooling tower makeup water, service water, and fire protection water for Unit #1. This authorization includes the 30 day emergency backup water supply for the cooling tower makeup water.

b. Authorized Annual Withdrawals

This Certification authorizes a maximum annual withdrawal of 1,218 MGY from the Floridan aquifer for cooling tower makeup water, service water, and fire protection water for Unit #1 prior to the availability of reclaimed water from the Ft. Pierce Utility Authority. After use of reclaimed water has commenced, this Certification authorizes a maximum annual withdrawal of 149.86 MGY from the Floridan aquifer for cooling tower makeup water, service water, and fire protection water for Unit #1. This authorization includes the 30 day emergency backup water supply for the cooling tower makeup water.

c. Reclaimed Water

Upon Notification from the SFWMD that the Ft. Pierce Utility Authority has a sufficient supply of reclaimed water to serve the project, the Licensee shall provide the SFWMD with a schedule for use of reclaimed water for the SFWMD's review and approval. Notwithstanding the provisions of conditions 2a and 2b above, the schedule may include provisions for continued withdrawals from the Floridan aquifer, as necessary, to adjust for the timing and quantity of available reclaimed water. Once the SFWMD approves the schedule, the SFWMD and the Licensee may jointly agree to further modify the approved schedule to account for unforeseen circumstances.

Reference: Sections 373.219, 373.223, and 373.250, F.S.; Rules 40E-2.091, 40E-2.041, 40E-¬2.301, and 40E-2.381, F.A.C.

d. Emergency Withdrawals

Any withdrawals from the Floridan aquifer in excess of the withdrawals authorized under this Certification shall require prior SFWMD approval. Any ground or surface water withdrawals from other sources shall require prior SFWMD approval. The SFWMD may grant such approval for any emergency withdrawals less than 90 days in duration without modifying these Conditions of Certification. The SFWMD's approval shall be based on the non-procedural requirements set forth in Chapter 40E-2, F.A.C.

e. Authorized Withdrawal Facilities

Prior to commencement of construction of Unit 1, the Licensee shall submit the details of the proposed withdrawal facilities (number of wells, well diameter, well depth, casing depth) for review and approval by the SFWMD. This condition shall be modified at a future date to reflect the specific withdrawal facilities authorized by the SFWMD.

f. Consistency Review of Authorized Withdrawals

Within five years from the date of issuance of the Certification Order and every five years thereafter, unless extended by mutual agreement between the Licensee and the SFWMD, the Licensee shall submit to the SFWMD a report on the project's consistency with the SFWMD's Water Use Conditions of Certification. Within 90 days after receipt of the completed report, the SFWMD shall evaluate the information contained therein and issue a written notification to the DEP and the Licensee as to whether the ground water withdrawals for consumptive use authorized by this Certification remain in compliance with the provisions of Chapter 373, F.S., and Chapter 40E-2, F.A.C., in effect at the time the certification was issued by the Siting Board. In determining whether the Licensee has established that its use of water complies with rule 40E-2 and the Basis of Review for Water Use Permit Applications within the SFWMD, the SFWMD shall evaluate whether the Licensee's use of water interferes with a legal use of water that existed at the time the certification was issued by the Siting Board. If the notification indicates that the withdrawals are not in compliance with these provisions, the SFWMD shall recommend to the Licensee possible alternatives for bringing the withdrawals into compliance with the SFWMD Water Use Conditions of Certification. In addition, if DEP determines, in consultation with SFWMD, based upon a review of a report submitted pursuant to this condition, that the Licensee has failed to establish that the Licensee's use of water meets the consumptive water use requirements described herein, DEP shall modify the authorization to use water in the certification or take other appropriate measures to ensure that the consumptive use of water meets the condition for issuance in Chapter 40E-2, F.A.C., as described herein. Any modification made pursuant to this condition shall not be subject to competing applications provided there is no increase in the allocation and no change in source.

g. Request for Modification of Withdrawals

The SFWMD may request a modification of the ground water withdrawals for consumptive use authorized by this Certification, in accordance with the provisions of Section 403.516, F.S. and Section 62-17.211, F.A.C. Any request for an increase in water withdrawals shall be made pursuant to the provisions of Section 403.516, F.S., and Section 62-17.211, F.A.C.

h. Dewatering Activities

Prior to commencement of construction of those portions of the project that involve dewatering activities, the Licensee shall submit a detailed plan for any such activities to the SFWMD for a determination of compliance with the non-procedural requirements of Chapters 40E-2, 40E-3 and 40E-20, F.A.C., in effect at the time of submittal. The following information, referenced to NGVD where appropriate, shall be submitted:

(1) A detailed site plan which shows the location(s) for each proposed dewatering area;

(2) The method(s) used for each dewatering operation;

(3) The maximum depth for each dewatering operation;

(4) The location and specifications for all proposed wells and/or pumps associated with each dewatering operation;

(5) The duration of each dewatering operation;

(6) The discharge method, route, and location of receiving waters generated by each dewatering operation, including the measures (Best Management Practices) that will be taken to prevent water quality problems in the receiving water(s);

(7) An analysis of the impacts of the proposed dewatering operations on any existing on and/or off-site legal users, wetlands, or existing groundwater contamination plumes;

(8) The location of any infiltration trench(es) and/or recharge barriers; and

(9) All plans must be signed and sealed by a Professional Engineer or a Professional Geologist registered in the State of Florida.

Reference: Sections 373.229 and 373.308, F.S.; Rules 40E-2.091, 40E-¬2.301, and 40E-3.500-531, F.A.C.

i. Reporting Requirements

Prior to the use of any proposed withdrawal facility authorized under this Certification, the Licensee shall equip each facility with a SFWMD-approved operating water use accounting system and submit a report of calibration to the SFWMD, pursuant to Section 4.1 of the Basis of Review For Water Use Permit Applications. In addition, the

Licensee shall submit a report of recalibration for the water use accounting system for each water withdrawal facility (existing and proposed) authorized under this Certification every five years from each previous calibration, continuing at five year increments. The Licensee shall report monthly withdrawals for each withdrawal facility to the SFWMD quarterly. The Licensee shall specify the water accounting method and means of calibration on each report. Reference: Section 373.223, F.S.; Rules 40E-2.091, 40E-2.301, and 40E-2.381, F.A.C.

j. Existing Well Repair, Replacement, Abandonment

If any of the existing on-site wells require repair, replacement, and/or abandonment, the Licensee shall submit the information described in Chapter 40E-3, F.A.C. for review by the SFWMD prior to initiating such activities. Reference: Sections 373.308 and 373.316, F.S.; Rules 40E-3.041, 40E-3.101, 40E-3.411, and 40E-3.500-531, F.A.C.

k. New Well Construction

Prior to construction of any new or replacement wells, the Licensee shall submit the drilling plans and other pertinent information required by Chapter 40E-3, F.A.C. to the SFWMD for review and approval. If the well locations are different from those approved in this Certification, the Licensee shall also submit to the SFWMD for review and approval an evaluation of the impacts of the proposed pumpage from the proposed well location(s) on adjacent existing legal users, pollution sources, environmental features, and water bodies. Reference: Section 373.223, F.S.; Rules 40E-2.091, 40E-2.301, and 40E-2.381, F.A.C.

l. Water Conservation Plan

Prior to operation of Unit 1, the Licensee shall submit a Water Conservation Plan, as required by Chapter 40E-2 in effect at that time, for review and approval by SFWMD staff. The plan shall, at a minimum, incorporate the following components:

(a) An audit of the amount of water needed in the Licensee's operational processes. The following measures shall be implemented within one year of audit completion if found to be cost effective in the audit:

(i) Implementation of a leak detection and repair program;

(ii) Implementation of a recovery/recycling or other program providing for technological, procedural or programmatic improvements to the Licensee's facilities; and

(iii)Use of processes to decrease water consumption.

(b) Development and implementation of an employee awareness program concerning water conservation.

XVI. Department of Community Affairs

The Licensee shall develop a Treasure Coast Energy Center hurricane preparation and recovery plan. The plan shall be submitted to the Department of Community Affairs and the St. Lucie County Office of Emergency Management no later than completion of building construction code compliance review of the Treasure Coast Energy Center by St. Lucie County. The Licensee shall formally update the plan every 5 years following commercial operation of the Treasure Coast Energy Center or whenever an additional generating unit is brought into commercial operation at the Treasure Coast Energy Center site and shall submit these updated versions of the plan to the Department of Community Affairs and the St Lucie County Office of Emergency Management. These updating and submittal requirements should be noted in the plan. If the Department deems the plan or any of its periodic updates not to be in compliance with the requirements of this condition, it may petition for enforcement of this condition pursuant to the Florida Electrical Power Plant Siting Act.

XVII. Florida Department of Transportation

A. Post-Certification Review of Specific Problems

1. Florida's Turnpike: All crossings of Florida's Turnpike will be subject to the requirements of the Department of Transportation's Utility Accommodation Manual (Document 710-020-001) and Rule Chapter 14-46, Utilities Installation or Adjustment, Florida Administrative Code. Although there is no major widening of the facility segment planned in the foreseeable future, due to the status of this roadway as a Florida Intrastate Highway system (FIHS) facility, the placement of the transmission lines should take into consideration the possible widening of this facility. If future widening should be required, the cost of relocating the transmission lines will be borne by the licensee unless the terms of Section 337.403, Florida Statues, are met.

2. Access Management to the State Highway System: Any access to the State Highway System is subject to the requirements of Rule Chapters 14-96, State Highway System Connection Permits, Administrative Process, and 14-97, State Highway System Access Management Classification System and Standards, Florida Administrative Code.

3. Overweight or Over Dimensional Loads: Operation of overweight or overdimensional loads by the Licensee or its contractors on State transportation facilities during construction and operation of the utility facility will be subject to safety and permitting requirements as defined in Chapter 316, Florida Statutes, and Chapter 14-26, Safety Regulations and Permitting Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

4. Use of State of Florida Right of Way or Transportation Facilities: Any use of State of Florida right-of-way and certain activities on State transportation facilities will be subject to the requirements of the Department of Transportation's Utility Accommodation Manual (Document 710-020-001) and Rule Chapter 14-46, Utilities Installation or Adjustment, Florida Administrative Code and Section 337.403, Florida Statutes.

5. Drainage: Any drainage onto State of Florida right-of-way and transportation facilities will be subject to the requirements of Chapter 14-86, Drainage Connections, Florida Administrative Code, including the attainment of any permit thereby.

6. Use of Air Space: Any structures proposed in the application which exceed 200 feet in height will be subject to an aeronautical study by the Federal Aviation authority under the provisions of 14 CFR Part 77. If the aero nautical study finds an adverse effect on the safe and efficient use of navigable airspace, the project will require the issuance of a variance by state or local government.

XXXI.A. Citation: Chapter 316, F.S. (2002); Chapters 14-26, 14-46, 14-86, 14-96 and 14-97, F.A.C.

B. Best Management Practices

1. Traffic control will be maintained during Project construction and maintenance in compliance with the standards contained in the Manual of Uniform Traffic Control Devices, Rule Chapter 14-94, Statewide Minimum Level of Service Standards, Florida Administrative Code; Florida Department of Transportation's Design Standards; and Florida Department of Transportation's Specifications for Roads and Bridge Construction; and the Department's Utility Accommodation Guide whichever is more stringent.

2. It is recommended that the licensee encourage transportation demand management techniques by doing the following:

a. Placing a bulletin board on site for car pooling advertisements.

b. Requiring that heavy construction vehicles remain onsite for the duration of construction.

3. If the licensee uses contractors for the delivery of any overweight or overdimensional loads to the site during construction, the licensee should ensure that its contractors adhere to the necessary standards and receive the necessary permits required under Chapter 316, Florida Statutes, and Chapter 14-26, Safety Regulations and Permitting Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code

XXXI.B. Citation: Chapter 14-94, F.A.C.

XVIII. TOXIC, DELETERIOUS OR HAZARDOUS MATERIALS

A. Spills

The spill of any toxic, deleterious, or hazardous materials shall be reported in the manner specified by Condition III.B., Noncompliance Notification.

B. Handling and Testing of Potentially Hazardous Material

The Licensee shall continue to implement its current plan for handling and disposing of any hazardous wastes.

XIX. BY-PRODUCT AND SOLID WASTE STORAGE

Any solid waste produced by the operation of theTCEC Facility shall be disposed of in an approved disposal facility. Industrial by-products that are to be sold for reuse or beneficially reused are not considered solid waste.

XXI. FEDERAL OPERATING PERMITS AND FEES

A. DEP Responsibilities

The Department of Environmental Protection shall implement the provisions of Title V of the 1990 Clean Air Act and the NPDES program for the Treasure Coast Energy Facility, developing Conditions of certification requiring submission of annual operating permit information and annual pollutant emission fees in accordance with any applicable provisions in federal law and federal regulations and sections 403.0885, 403.0872, 403.5055, 403.509, and 403.511, F.S.

B. Licensee Responsibilities

The Licensee shall submit the appropriate annual operating information as well as the appropriate annual pollutant emission and NPDES fees, as required by federal law, to the Department.

XXII. Florida Fish and Wildlife Conservation Commission

A. Burrowing Animals: Surveys shall be conducted prior to construction throughout the upland areas within the construction footprints. Where possible, take of these species or their burrows should be avoided by staking out a flagged buffer of 25 feet for gopher tortoises (FWC 2004a) and 50 to 150 feet for burrowing owls (FWC 2004b) around each burrow or group of burrows prior to construction. Workers should be informed of the purpose of the flagging and instructed not to disturb the burrows. With regard to any burrows located such that take would be unavoidable, the permitting requirements of FWC must be complied with. Please consult the FWC website for further information and permit requirements (http://myfwc.com/permits/Protected-Wildlife/default.htm), or contact Ricardo Zambrano in the FWC's South Regional office at 561-625-5122. In the event that eastern indigo snake or nests of the wood stork, kite, or eagle are found during pre-construction surveys, impacts can be avoided by consulting with the U.S. Fish and Wildlife Service (FWS) shall also be consulted, and their guidelines adhered to.

B. Wetland Habitat: The proposed 11-acre stormwater detention area on-site could offer an opportunity to provide some benefits in terms of wetland habitat. The applicant should consider designing and planting the area such that it can support native littoral and transitional upland vegetation around its perimeter. Establishment of native vegetation around the detention area may provide water quality benefits by assisting in nutrient uptake from stormwater runoff and would also provide some fish and wildlife habitat value.

XXIII. Treasure Coast Regional Planning Council

A. Treated Sewage Effluent

In accordance with the SFWMD Condition XV.B.2.c, concerning reclaimed water, upon notification from SFWMD that, in accordance with the Distict's statutes and rules, the

City of Port St. Lucie has a sufficient supply of reclaimed water to serve the project, TCEC shall provide the SFWMD with a schedule for the SFWMD's review and approval, for the TCEC's use of reclaimed water from the City of Port St. Lucie in order to avoid using ground water until such a time as the Fort Pierce Utilities Authority is able to provide reclaimed water to the site.

B. Wetland Mitigation

TCEC shall provide wetland mitigation within the watershed of the North Fork of the St. Lucie River as proposed through the use of the Bluefield Ranch Wetlands Mitigation Bank or other similar mitigation bank serving St. Lucie County, in accordance with Conditions XXIV.A.1 and XXV.A.3.

XXIV. Onsite Wetlands Resource Management

A. Mitigation

1. The Licensee shall provide mitigation for onsite Project-related wetlands impacts by obtaining wetlands mitigation credits from the Bluefield Ranch Mitigation Bank or other permitted wetlands mitigation bank serving the Project site. Within 90 days after issuance of the site certification or 30 days prior to commencement of construction of the Project, the Licensee shall provide the Siting Coordination Office with documentation of the final purchase of the required mitigation credits and deduction of those credits from the wetlands mitigation bank's ledger. If the Project results in additional wetland impacts not covered by this certification, then additional wetlands mitigation information shall be submitted to the Department. Upon receiving complete information, the Department will assess the revised mitigation plan within 90 days. If the Department, upon review of the proposed mitigation, determines that the proposed mitigation is inadequate to offset the additional wetland loss and habitat degradation from this project, the Licensee shall propose additional mitigation.

2. Prior to construction of work authorized by this certification, the Licensee shall provide written notification of the date of commencement of construction to the Southeast District Office of the Florida Department of Environmental Protection, 400 N. Congress Ave. Suite 200, West Palm Beach, Florida 33401.

3. Turbidity controls shall be utilized at all locations where sediment has the potential to reach nearby wetlands until construction in the area is completed. The turbidity controls shall be maintained throughout the duration of the project, and shall be effective in preventing soil from the fill pad from eroding into the adjacent unimpacted wetlands.

4. Within 30 days of completion of work authorized by this certification, the Licensee shall provide written notification of the date of completion of construction to the Southeast District Office of the Florida Department of Environmental Protection, 400 N. Congress Ave. Suite 200, West Palm Beach, Florida 33401.

5. The limits of construction within the unimpacted wetlands shall be delineated by a continuous plastic flagging tape and with a turbidity barrier/control. The Licensee bears the responsibility of notifying all construction workers that the flagging and barriers represent the limits of all construction activities. The Licensee shall bear the responsibility of keeping all construction workers and equipment out of the wetland or surface water areas, which has not been permitted for impacts.

6. There shall be no storage or stockpiling of tools or materials within the unimpacted wetlands.

7. If any damage occurs to wetlands or surface waters as a result of any construction activities, the Licensee shall be required to restore the wetland area(s) or

surface waters by re-grading the damaged areas back to the natural preconstruction elevations and planting vegetation of the size, densities and species that exist in the adjacent areas. The restoration shall be completed within 30 days of completion of the construction unless a later date is agreed to by the Department and shall be done to the satisfaction of the Department.

8. All material used as fill in wetland areas shall be clean material and shall not be contaminated with vegetation, garbage, trash, tires, hazardous, toxic waste or other materials that are not suitable within waters of the State as so determined by the Department.

9. The fill and associated side slopes that will be placed in wetlands on the property shall be stabilized.

B. Water Quality Standards

The project shall comply with applicable state water quality standards, including:

1. Rule 62-302.500, F.A.C. - minimum criteria for all surface waters at all places and at all times,

2. Rule 62-302.500, F.A.C. - Surface waters: general criteria,

3. Rule 62-302.400, F.A.C. - Class III Waters - Recreation, Propagation and maintenance of a healthy, well balanced population of Fish and Wildlife, and

4. Rule 62-302.530(70), F.A.C. - Turbidity shall not exceed 29 Nephelometric Turbidity Units above background.

XXV. Construction of Offsite Linear Facilities

A. Linear Facilities

1. The certified corridors for the linear facilities consisting of two electrical transmission lines and the natural gas pipeline are depicted by Figure 6.1-1 in the application.

2. Construction of the planned linear facilities, including the transmission lines and natural gas pipeline lateral shall be undertaken in accordance with the plans submitted in the Application.

3. Once the final right-of-way has been established for the transmission line or natural gas pipeline, the Licensee shall propose any additional mitigation necessary to offset any proposed wetland impacts.

4. Prior to construction of linear facilities authorized by this certification, the Licensee shall provide written notification of the date of commencement

of construction to the Southeast District Office of the Florida Department of Environmental Protection, 400 N. Congress Ave. Suite 200, West Palm Beach, Florida 33401.

5. Turbidity controls shall be utilized at all locations where sediment has the potential to reach nearby wetlands until construction in the area is completed. The turbidity controls shall be maintained throughout the duration of the project, and shall be effective in preventing soil from the fill pad from eroding into the adjacent wetlands.

6. Within 30 days of completion of work authorized by this certification, the Licensee shall provide written notification of the date of completion of construction to the Southeast District Office of the Florida Department of Environmental Protection, 400 N. Congress Ave. Suite 200, West Palm Beach, Florida 33401.

7. The limits of construction within unimpacted wetlands on the right-of-way shall be delineated by a continuous plastic flagging tape and with a turbidity barrier/control. The Licensee shall bear the responsibility of notifying all construction workers that the flagging and barriers represent the limits of all construction activities. The Licensee shall bear the responsibility of keeping all construction workers and equipment out of the wetland or surface water areas, which have not been permitted for impacts.

8. There shall be no storage or stockpiling of tools or materials within unimpacted wetlands.

9. If any damage occurs to unimpacted wetlands or surface waters as a result of any construction activities for the linear facilities, the Licensee shall be required to restore the wetland area(s) or surface waters by re-grading the damaged areas back to the natural preconstruction elevations and planting vegetation of the size, densities and species that exist in the adjacent areas. The restoration shall be completed within 30 days of completion of the construction and shall be done to the satisfaction of the Department.

10. All material used as fill in wetlands areas shall be clean material and shall not be contaminated with vegetation, garbage, trash, tires, hazardous, toxic waste or other materials that are not suitable for construction within waters of the State as so determined by the Department.

11. The fill and associated side slopes (for example for any key hole pads) that will be placed in wetlands within rights of way for the linear facilities shall be stabilized.

12. The construction of linear facilities shall comply with applicable state water quality standards, including:

a. 62-302.500 - minimum criteria for all surface waters at all places and at all times,

b. 62-302.500 - Surface waters: general criteria,

c. 62-302.400 - Class III Waters - Recreation, Propagation and maintenance of a healthy, well balanced population of Fish and Wildlife, and

d. 62-302.530(70) - Turbidity shall not exceed 29 Nephelometric Turbidity Units above background.

13. For any post-certification submittal which addresses matters within DEP's environmental resource permitting jurisdiction, DEP shall provide to the U.S. Army Corps of Engineers a letter in accordance with DEP Rule 62-17.665(7)(f), F.A.C. This letter shall be sent concurrently with a determination of compliance pursuant to Condition III.I.5. above, or immediately upon a request by the Licensee submitted more than 60 days after the filing of a sufficient post-certification submittal addressing matters within DEP's environmental resource permitting jurisdiction.

14. For each post-certification submittal, which addresses activities located within joint jurisdictional wetlands or surface waters, that provides reasonable assurance of compliance with the conditions of certification, DEP shall provide to the U.S. Army Corps of Engineers a letter indicating that the activities are consistent with the federally-approved Florida Coastal Zone Management Program.

15. Dredging and filling in association with the installation of the transmission lines and the natural gas pipeline shall be limited to only that necessary to install the transmission line or pipeline.

a. All disturbed areas, except access roads and structure pads, shall be restored to their pre-existing ground surface conditions and elevations.

b. Construction techniques necessary for the installation of the gas pipeline, including transport and placement of material shall not disturb wetlands or surface waters adjacent to the construction right-of-way and shall not adversely affect water quality.

c. During construction and while conducting normal maintenance activities, the applicant/Licensee shall eradicate all Brazilian pepper, Australian pine and Melaleuca trees from the wetland portions of the right-of-way.

16. If the construction of the offsite linear facilities causes additional unanticipated wetlands impacts, mitigation may be required. For construction in wetlands that requires mitigation, the Licensee shall propose a mitigation plan as a post-certification submittal under Condition XXIV. The Licensee may obtain credits from a permitted wetlands mitigation bank serving the Project area. If the Licensee proposes to undertake mitigation, the Licensee shall provide the following information to the DEP Southeast District Environmental Resource Permitting Section for review:

a. Detailed description, location map, and recent aerial photograph of each wetland impact area in which the Rule 62-341.620(2)(b)-(i), F.A.C. limitations were not met;

b. Acreage of the type and quality of wetland being impacted at each such site;

c. Narrative, drawings, location map, and aerial photographs showing and explaining the proposed mitigation;

d. Detailed description of the existing conditions at the impact site and at the mitigation area;

e. Acreage and wetland type of the proposed mitigation;

f. Documentation providing reasonable assurance that the proposed mitigation will be successful; and

g. An analysis pursuant to Chapter 62-345, F.A.C., to the extent applicable.

17. Mitigation plans must be found to fully offset the functions and values provided by wetlands that will be degraded or eliminated. DEP will work with the Licensee in the development of acceptable mitigation plans. The mitigation plans proposed by Licensee shall be submitted for review and compliance monitoring to DEP under Condition III.I.

18. If DEP, upon review of the proposed mitigation plan, determines that the proposed mitigation is inadequate to offset the wetland loss and habitat degradation from this project, Licensee may propose additional or alternative mitigation or dispute the determination pursuant to Condition XXVI.

19. If the proposed mitigation plan is deemed acceptable by DEP, DEP shall establish construction conditions, success criteria and a monitoring plan to be carried out for the approved mitigation in accordance with DEP Rule 62-354, F.A.C. These conditions, criteria and monitoring plan shall be incorporated into the certification conditions as an Attachment.

20. No construction within wetlands, located within rights-of-way and which are subject to the regulatory jurisdiction of DEP that does not comply with the non-procedural limitations of Rule 62.341.620(2)(b)-(i), F.A.C., shall commence until DEP approves a mitigation plan for those additional wetland impacts, and mitigation construction conditions, success criteria and a monitoring plan are approved in accordance with these certification conditions.

21. The Licensee shall be deemed to have met the requirements of this condition if Licensee satisfies the criteria of either Section 4.3 or 4.4 of the Basis of Review for Environmental Resource Permit Applications.

C. Process for Review of ROW Location

1. Prior to the finalization of the ROW location, three copies of blue-line reproductions of the most recent available aerial photographs at a scale of 1" = 400' with wetland locations generally identified shall be submitted to DEP Siting Coordination Office, and one copy each to DEP Southeast District Office, SFWMD, DOT, DCA, and St. Lucie County, delineating the certified corridor, and the selected transmission line or gas pipeline ROW. In addition, FMPA shall note on the aerial photographs new development within the corridor that has occurred since the photograph was taken. FMPA shall notify all parties of such filing and, if needed, shall meet with DEP to discuss the ROW location. This information may be submitted in segments. The agencies receiving copies of the aerial photographs from FMPA shall have an opportunity to review the photographs and to notify DEP Siting Coordination Office of any apparent conflicts with the requirements of the Conditions of Certification. However, this paragraph shall not operate to avoid the need for post-certification submittals and compliance reviews otherwise required by the Conditions of Certification.

2. After review of the aerial photographs and comments from the other reviewing agencies, if DEP Siting Coordination Office has reason to believe that the construction of the transmission lines, gas pipelines, access roads or pads within FMPA's designated ROWs cannot be accomplished in compliance with the Conditions of Certification, FMPA may be so notified in writing, with copies to other parties to the certification proceeding of the particular basis for DEP's conclusion, and possible corrective measures which would bring the Project into compliance. If such notice is not received within 15 days of FMPA's submittal of the aerial photographs to the agencies, FMPA may proceed with design of the transmission line on the noticed ROW.

3. The acquisition of a particular ROW or the expenditure of funds toward acquisition of a particular ROW prior to the agencies' review pursuant to this condition will be at the Licensee's risk, and no party will be estopped by such acquisition to seek disapproval of the construction of the transmission line or access road within the ROW in accordance with these Conditions of Certification.

4. After the Licensee has acquired interest in the entire length of the transmission line or gas pipeline ROW in a county, the Licensee shall:

a. File a statement with the clerk of the circuit court for each county through which the corridor passes certifying that all lands required for the transmission line or gas pipeline ROW within the corridor have been acquired. The Licensee shall also file with the county Planning Department a map at the scale of 1" = 400' showing the boundaries of the acquired ROW.

b. File with DEP Siting Coordination Office a map at a scale of 1" = 400' showing the boundaries of the acquired ROW, if such boundaries are different from those shown in the filing required by Condition XXV.C.1. above. Such maps shall comply with the requirements of Condition XXV.C.1. If the boundaries have not changed, the Licensee shall file a statement with DEP Siting Coordination Office accordingly.

XXVI. DISPUTE RESOLUTION

If a situation arises in which mutual agreement cannot be reached between DEP and another agency receiving a post-certification submittal or between DEP and FMPA regarding compliance with the Conditions of Certification, then the matter shall be immediately referred to the Division of Administrative Hearings (DOAH) for disposition in accordance with the provisions of Chapter 120, F.S.

Adams, Patty

From: Mulkey, Cindy
Sent: Thursday, January 12, 2006 2:29 PM
To: Adams, Patty
Cc: Mulkey, Cindy
Subject: TCEC corrections to Draft Permit

Patty,

Please file this in the Treasure Coast Energy Center file.

This is to document phone conversations with FMPA (Susan Schumann) and Black & Veatch (Bob Holmes) regarding the TCEC project

No. 1110121-001-AC (PSD-FL-353). Some of the mass emission rates (lb/hr) listed in Condition 13, Emission Standards do not precisely coincide with the mass emission rates submitted by the applicant for the given concentration. This is due to the fact that I made independent calculations using an f-factor and the given heat input rate for each concentration.

The differences are less than ± 2 % and in most cases less than ± 1%. I have agreed to make the changes as corrections to the draft permit.

Modeling was based on the rates submitted in the application. The changes will not impact any determination made by the department.

Cindy

Cindy Mulkey
Engineering Specialist
Bureau of Air Regulation
Permitting South
(850) 921-8968
FAX (850)921-9533
SC 291-8968

Treasure Coast Energy Center Draft PSD-FL-353
Explanation of proposed revisions submitted by FMPA

Comment number	Corresponding page number in draft permit	Corresponding Condition in draft permit	Explanation of Revision / Comment
1	1	n/a	Expiration of permit should be extended to July 31, 2009, to allow for flexibility in construction schedule
2	1	n/a	Thomas W. Richards of FPUA will be the Authorized Representative for Treasure Coast Energy Center
3	2	n/a	Subpart KKKK applicability will be dependent upon the final rule wording; applicability may change from original proposed language
4	5	2.(d)	Correction for the date of the proposed NSPS standard
5	5	2.(d)	Subpart KKKK applicability will be dependent upon the final rule wording; applicability may change from the original proposed language
6	5	4.	Revision of maximum heat input rate from 565 MMBtu to 565.3 MMBtu, consistent with page 16 of the TCEC PSD application.
7	6	7.	Revision of reference from 40 CFR 60.130 (NSPS for brass and bronze production plants) to 40 CFR 68.130 (lists substances under Chemical Accident Prevention provisions)
8	6	8.	The Combustion Turbine has been purchased, and the final performance runs indicate the fuel oil heat input will be slightly higher, revised from 1,967MMBtu to 1,986MMBtu per hour.
9	6	9.	Revision of maximum heat input rate from 560 MMBtu to 565.3 MMBtu, as noted on page 16 of the TCEC PSD application
10	7	12.d.	Duct firing will not be limited to only natural gas firing of the combustion turbine. This is consistent with page TE-5 of the Technical Evaluation document, where FDEP recognizes that FMPA "requests unlimited use of duct burning...while firing either gas or oil in the combustion turbine."
11	8	13.	FMPA understands calendar 12-month-annual-average will be utilized as CEMS block average.
12	8	13.b.	Revision of language from "shall" to "may," consistent with 13.a
13	9	14.	Clarification of language to reflect proper training for maintenance procedures. Due to the complexity of the units, operators are not trained to "maintain" the units, but they will be trained to identify, troubleshoot, and coordinate maintenance items.
14	11	22.	Clarification of language to add "for good cause."
15	11	24.	Suggest removing sentence from permit. Condition 13 specifically indicates that short-term limits are based on stack tests.
16	14	30.b.	Clarification of language to reflect fuel sampling procedures to include permittee or vendor.
17	17	2.	Clarification of language to reflect commercial operation.
18	18	n/a	Engineer,Procure,Construct (EPC) final specification includes 750kw/1000hp generator – TCEC permit application estimated 765hp. FMPA is currently working with FDEP to address the revisions to the proposed safe shutdown generator.
19	18	n/a	Include language to accurately describe Emission Unit

PERMITTEE:

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Treasure Coast Energy Center
DEP File No. 1110121-001-AC
Permit No. PSD-FL-353
SIC No. 4911
Expires: July 31, ~~2008~~ 2009

1. *Authorized Representative:*

2. ~~Daniel Cassel, Director of Generation~~
Thomas W. Richards FPUA
Director of Electric and Gas Systems

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 300 MW gas-fired combined cycle electrical power plant. The project will include one 170 MW combustion turbine generator, one heat recovery steam generator, a 130 MW steam turbine generator, a fuel oil storage tank, a mechanical draft cooling tower, and auxiliary equipment. The project will be located southwest of the city of Fort Pierce, East of Highway 95 in St. Lucie County.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendices are made a part of this permit:

Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determination and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements
Appendix GC	Construction Permit General Conditions
Appendix GG	NSPS Subpart GG Requirements
Appendix SC	Standard Conditions

Michael G. Cooke, Director
Division of Air Resources Management

Date:_______________

FACILITY DESCRIPTION

The proposed FMPA facility is a combined cycle power plant. The project is to install one combined cycle unit which will consist of one gas turbine (nominal 170 MW) and one heat recovery steam generator with supplementary duct firing, a steam turbine-electrical generator (nominal 130 MW), a mechanical draft cooling tower, and one 990,000 gallon fuel oil storage tank. Ancillary equipment includes a diesel engine driven fire pump with associated 500 gallon fuel oil tank, and a safe shutdown generator.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions unit:

EU ID NO.	EMISSION UNIT DESCRIPTION
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

REGULATORY CLASSIFICATION

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

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

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes
3. final, the facility ~~will~~ may be subject to Subpart KKKK, and may no longer be subject to subparts GG and Da. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a "Major Source" of HAPs and Unit 1 is <u>not</u> subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

SECTION I - GENERAL INFORMATION

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Southeast District, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit; however, they are specifically related to this permitting action and are on file with the Department.

- Application received on April 14, 2005
- Department's Determination of Sufficiency – Found Insufficient June, 6 2005
- FMPA Sufficiency responses dated July 28, 2005
- Department's Second Determination of Sufficiency – Found Sufficient August 29, 2005
- Department's Intent to Issue and Public Notice Package dated October 28, 2005
- Letter from EPA Region IV dated __XXX________
- Final Certification by the Power Plant Siting Board on XXXX; and
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

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

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

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. 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.]

5. 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. [Chapters 62-210 and 62-212, F.A.C.]

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

7. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

A. Unit 1 Combined Cycle Gas Turbine (EU 001)

This section of the permit addresses the following emissions unit.

E.U. ID	Emission Unit Description
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards for Subpart Da, Subpart GG, and Subpart KKKK (as proposed). Some separate reporting and monitoring may be required by the individual subparts.

   (a) **Subpart A, General Provisions**, 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
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Subpart Da, Standards of Performance for Electric Utility Steam Generating Units** These provisions include standards for duct burners.

   (c) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

4,5 (d) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions were published February 18, ~~2004~~ 2005 as a proposed new NSPS standard. The final rule ~~will be~~ may applicable to Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

EQUIPMENT

3. Gas Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 170 MW. The gas turbine will be equipped with DLN combustors, and an inlet air filtration system with evaporative coolers. The unit shall include the Speedtronic™ Mark VI automated gas turbine control system, and will have dual-fuel capability. [Application; Design]

4. HRSG: The permittee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG may be equipped with
6 supplemental gas-fired duct burners having a maximum heat input rate of ~~565~~ 565.3 MMBtu per hour (HHV).

The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. [Application; Design]

CONTROL TECHNOLOGY

5. <u>DLN Combustion</u>: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

6. <u>Water Injection</u>: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for the gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

7. <u>Selective Catalytic Reduction (SCR) System</u>: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

7. *Ammonia Storage:* In accordance with 40 CFR ~~60.130~~ 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

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

PERFORMANCE RESTRICTIONS

8. <u>Permitted Capacity – Gas Turbine</u>: The maximum heat input rate to the gas turbine is 1,787 MMBtu per
8. hour when firing natural gas and ~~1,967~~ 1,986 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

9. <u>Permitted Capacity - HRSG Duct Burners</u>: The total maximum heat input rate to the duct burners for the
9. HRSG is ~~560~~ 565.3 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

10. <u>Hours of Operation</u>: The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

11. <u>Authorized Fuels</u>: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. The

gas turbine shall fire no more than 500 hours of fuel oil, regardless of mode, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

12. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

    a. *Combined Cycle Operation*: The gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

    b. *Pseudo Simple Cycle Operation*: The gas turbine/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

    c. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."

10. d. *Duct Firing*: ~~When firing natural gas,~~ Tthe HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

[Application; Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

EMISSIONS STANDARDS

13. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[f]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
11.	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X[b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10}[c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia[e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of
12. compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments ~~shall~~ may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, established in Condition No. 11 of this section, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be determined by the requirements in Condition No. 30 of this section. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, established in Condition No. 11 this section, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 30 of this section.

e. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

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

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

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

15. Definitions

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
    [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
    [Rule 62-210.200(230), F.A.C.]

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
    [Rule 62-210.200(159), F.A.C.]

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

17. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

18. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine/HRSG system, excess emissions from the gas turbine/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue}

b. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *Shutdown:* For shutdown of the combined cycle operation, excess emissions from the gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

d. *Fuel Switching:* Excess emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbine/HRSG system including the pollution control equipment. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Determinations: The gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. The unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate
14. compliance with the CO and NO_X mass rate emissions standards. The Department may for good cause require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

23. Annual Compliance Tests: During each federal fiscal year (October 1st, to September 30th), the gas turbine shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NOX emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. ~~The Department also reserves the right to use data from the continuous monitoring record and from annual~~
15. ~~RATA tests to determine compliance with the short-term CO and NO_X limits for each method of operation given in Condition 12 above.~~ [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

   a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

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

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 18 and 20 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Availability:* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

RECORDS AND REPORTS

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

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

the permittee or vendor

16. b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Report:* Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Reports:* For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority. This also includes reporting any periods of excess emissions as applicable and defined by NSPS Subpart KKKK when the rule is finalized.

{Note: If there are no periods of excess emissions as defined in NSPS Subparts GG, Da, or KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

33. <u>Annual Operating Report</u>: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

C. Fuel Oil Storage Tank (EU 002)

ID	Emission Unit Description
002	One distillate fuel oil storage tank for Unit 1 combustion turbine (approximately 1 million gallons).

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 5.2 kPa and greater than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the monitoring requirements. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. The fuel oil storage tank (EU 002) has a capacity greater than 151 cubic meters and the vapor pressure of the ultra low sulfur fuel oil is less than 3.5 kPa; therefore NSPS Kb, including the monitoring requirements, does not apply to this unit.
[40 CFR 60.110b(a) and (b), and 60.116b(c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one 990,000 gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 1 gas turbine. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year).
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for use in the Annual Operating Report.
[Rule 62-204.800(7)(b)16, F.A.C]

C. Cooling Tower (EU 003)

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

ID	Emission Unit Description
003	One 8-cell mechanical draft cooling tower.

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one 8-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 111,130 gpm; a design air flow rate of 1,000,000 acfm per cell; drift eliminators; a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

17. 2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 10 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

D. Safe Shutdown Generator (EU 004)

This section of the permit addresses the following emissions unit.

18,19

ID	Emission Unit Description
004	One safe shutdown generator (approximately ~~765~~ 1000 hp) with associated 1000 gallon fuel oil storage tank.

NESHAPS APPLICABILITY

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

EQUIPMENT SPECIFICATIONS

1. Safe Shutdown Generator: The permittee is authorized to install, operate, and maintain one safe shutdown generator. The safe shutdown generator may operate when the transmission connection is lost and the plant shuts down, and during occasional testing to ensure operability. The safe shutdown generator will fire ULS fuel oil. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Hours of Operation: The safe shutdown generator may operate 200 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

{Permitting Note: Emissions from the safe shutdown generator are included in the potential to emit for the project.}

E. Diesel Fire Pump (EU 005)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
005	One diesel engine fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank.

NESHAPS Applicability

<u>NESHAPS Subpart ZZZZ Applicability</u>: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

Equipment Specifications

1. <u>Fire Pump</u>: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank. The diesel engine fire pump will fire ULS fuel oil. [Application; Design]

Emissions and Performance Requirements

<u>Hours of Operation</u>: The fire pump may operate 200 hours per year.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.

{Permitting Note: The fire pump is considered emergency equipment, therefore exempt from permitting, however its emissions are included in the potential to emit for the project.}

Florida Municipal Power Agency

Tina Garza
Document Control Technician

Via Federal Express

RECEIVED
NOV 15 2005
BUREAU OF AIR REGULATION

Cindy Mulkey
Engineering Specialist
Division of Air Resource Management
2600 Blair Stone Road, MS # 5505
Tallahassee, FL 32399-2400

Re: Treasure Coast Energy Center
Combined Cycle Power Project
DEP File No. 1110121-001-AC (PSD-FL-353, PA 05-48)

November 14, 2005

Dear Ms. Mulkey:

Enclosed is the original of the proof of publishing and the Affidavit of Publication in the Fort Pierce Tribune for the Treasure Coast Energy Center's "Notice of Intent to Issue PSD Permit". If you should need anything else please feel free to call me at 321-23-1020.

Sincerely,

Tina Garza

Tina Garza
Document Control Technician

Enclosure

8553 Commodity Circle | Orlando, FL 32819-9002
T. (407) 355-7767 | Toll Free (888) 774-7606
F. (407) 355-5794 | www.fmpa.com
tina.garza@fmpa.com

SCRIPPS HOWARD

SCRIPPS TREASURE COAST NEWSPAPERS

Fort Pierce Tribune

600 Edwards Road, Fort Pierce, FL 34982

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, S. Darlene Mailing, who on oath says that she is Classified Inside Sales Manager of the Fort Pierce Tribune, a daily newspaper published at Fort Pierce in St. Lucie County, Florida: that the attached copy of advertisement was publshed in the Fort Pierce Tribune in the following issues below. Affiant further says that the said Fort Pierce Tribune is a newspaper published in Fort Pierce, in said St. Lucie County, Florida, and that said newspaper has heretofore been continuously published in said St. Lucie County, Florida, daily and distributed in St. Lucie County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid or promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper. The Fort Pierce Tribune has been entered as Periodical Matter at the Post Offices in Fort Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Customer	Ad Number	Pub Date	Copyline	PO #
FLORIDA MUNICIPAL POWER AG	1259989	11/4/2005	NOTICE OF INT PERMIT	DEP #1110121001AC

Subscribed and sworn to me before this date:

November 04, 2005

S. Darlene Mailing

Mary T Byrne

Notary Public

MARY T. BYRNE
Notary Public - State of Florida
My Commission Expires Aug 2, 2008
Commission # DD132804
Bonded By National Notary Assn.

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 1110121-001-AC, PSD-FL-353, and PA 05-48
FMPA Treasure Coast Energy Center
Combined Cycle Power Project
St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD Permit) of Air Quality to Florida Municipal Power Agency. The permit is to construct a nominal 300 megawatt (MW) combined cycle electrical power generating plant at the Treasure Coast Energy Center near Fort Pierce, St. Lucie County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400, Florida Administrative Code (F.A.C.), for emissions of particulate matter (PM/PM10), carbon monoxide (CO), sulfur dioxide (SO2), sulfuric acid mist, and nitrogen oxides (NOX). The applicant's name and address are Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida 32819.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 130 MW separate steam-electrical generator, a 170-foot stack, a mechanical draft cooling tower with drift eliminators, a 990,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up ultra low sulfur (ULS) fuel oil (0.0015 percent sulfur) will be burned for a maximum of 500 hours per year.

NOx emissions will be controlled by selective catalytic reduction (SCR) to achieve 2 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 8 ppmvd while burning ULS fuel oil. Emissions of CO will be controlled to 4.1 and 8 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM10, SO2, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and ULS fuel oil. Ammonia emissions (NH3) generated due to NOX control will be limited to 5 ppmvd.

FMPA's estimates of maximum potential annual emissions from the project are summarized in the following table.

Pollutants	Maximum Potential Emissions Tons Per Year	PSD Significant Emission Rate Tons Per Year
CO	231	100
NO_x	90	40
PM/PM_{10}	176/171	25/15
Sulfuric Acid Mist	22.4	7
SO_2	56.6	40
VOC	23.4	40
Lead	0.007	0.6
Mercury	0.001	0.1
HAPs	12.5	NA

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park and the Chassahowitzka Wilderness Area (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The project has no significant impact on the PSD Class I Chassahowitzka Wilderness and Everglades National Park areas. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

BEST AVAILABLE COPY

A person whose substantial interests are affecte
decision may petition for an administrative prothe proposed permitting
tions 120.569 and 120.57 of the Florida Statutesg (hearing) under sec-
the information set forth below and must be filepetition must contain
General Counsel of the Department at 3900 Comived) in the Office of
Station #35, Tallahassee, Florida, 32399-3000. Pealth Boulevard, Mail
applicant or any of the parties listed below mustfiled by the permit
days of receipt of this notice of intent. Petitions filed within fourteen
than those entitled to written notice under section any persons other
Statutes must be filed within fourteen days of public3) of the Florida
tice or within fourteen days of receipt of this notice of the public no-
curs first. Under section 120.60(3), however, any perso whichever oc-
partment for notice of agency action may file a petition asked the De-
of receipt of that notice, regardless of the date of publifourteen days
shall mail a copy of the petition to the applicant at the A petitioner
above at the time of filing. The failure of any person to fiss indicated
the appropriate time period shall constitute a waiver of thatition within
request an administrative determination (hearing) under 's right to
and 120.57 F.S., or to intervene in this proceeding and partics 120.569
to it. Any subsequent intervention will be only at the approvas a party
ing officer upon the filing of a motion in compliance with Rule presid-
the Florida Administrative Code. 6.205 of

A petition that disputes the material facts on which the Departme
based must contain the following information: (a) The name and ss of
each agency affected and each agency's file or identification er, if
known; (b) The name, address, and telephone number of the peti the
name, address, and telephone number of the petitioner's represe if
any, which shall be the address for service purposes during the cours the
proceeding; and an explanation of how the petitioner's substantial ists
will be affected by the agency determination; (c) A statement of ho nd
when petitioner received notice of the agency action or proposed actio d)
A statement of all disputed issues of material fact. If there are none, the ti-
tion must so indicate; (e) A concise statement of the ultimate facts alleg,
including the specific facts the petitioner contends warrant reversal or mo
fication of the agency's proposed action; (f) A statement of the specific rule
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 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southeast District Branch Office
1801 SE Hillmoor Dr., Suite C-204
Port St. Lucie, Florida 34952
Telephone: 772/398-2806
Fax: 772/398-2815

Dept. of Environmental Protection
Southeast District Office
400 North Congress Avenue, Suite 200
West Palm Beach, Florida 334018
Telephone: 561/681-6774
Fax: 561/681-6755

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/treasurecoast.htm

Publish: November 4, 2005 1259989

Memorandum

Florida Department of
Environmental Protection

TO: Trina L. Vielhauer

THRU: A.A. Linero

FROM: Cindy Mulkey

DATE: October 25, 2005

SUBJECT: FMPA Treasure Coast Energy Center
300 MW Combined Cycle Plant
DEP File No. 1110121-001-AC (PSD-FL-353, PA 05-48)

Attached is the public notice package for construction of a 300 MW Combined Cycle Plant at the Treasure Coast Energy Center in St. Lucie County.

The basic unit is a nominal 170-megawatt General Electric 7FA gas and oil-fired combustion turbine-generator. The project includes a duct fired HRSG that will raise sufficient steam to produce another 130 MW via a steam-driven electrical generator. A selective catalytic reduction system including ammonia storage is included.

A 990,000 gallon storage tank will be constructed for the back-up ultra low sulfur fuel oil that will be used for no more than 500 hours per year.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by SCR to 2 ppmvd (gas) and 8 ppmvd (oil). The ammonia limit is proposed at 5 ppmvd by agreement with the applicant. This will reduce formation of ammoniated particulate species.

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

The project was deemed complete on August 28th upon receipt of FMPA's response to Power Plant Siting's Statement of Insufficiency. The proposed issue date of October 28 is Day 60.
I recommend your signature and approval of this Intent to Issue.

AAL/cm

Attachments

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

October 28, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger A. Fontes, General Manager and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Re: Treasure Coast Energy Center
Combined Cycle Power Project
DEP File No. 1110121-001-AC (PSD-FL-353, PA 05-48)

Dear Mr. Fontes:

Enclosed are documents indicating the Department's intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to the Florida Municipal Power Agency for construction of a 300 megawatt combined cycle unit and associated support facilities at the proposed Treasure Coast Energy Center. The documents include: the "Intent to Issue Air Construction Permit;" the "Public Notice of Intent to Issue Air Construction Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The "PUBLIC NOTICE" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, Program Administrator, Permitting South Section, at the above letterhead address. If you have any questions, please call Ms. Cindy Mulkey at 850/921-8968 or Ms. Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/cem

Enclosures

In the Matter of an
Application for Permit by:

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative:
Mr. Roger A. Fontes, General Manager and CEO

DEP File No. 1110121-001-AC
Draft Permit No. PSD-FL-353
Siting No. PA 05-48
Treasure Coast Energy Center
300 MW Combined Cycle Unit

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD Permit), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Florida Municipal Power Agency, applied on April 14, 2005 (sufficient August 29) to the Department for a PSD permit to construct a nominal 300 megawatt combined cycle combustion turbine project at the proposed Treasure Coast Energy Center near Fort Pierce, St. Lucie County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD construction permit is required.

The Department intends to issue this PSD permit based on the belief that reasonable assurances have been provided to indicate that operation of these emissions units will not adversely impact air quality, and the emissions units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue PSD Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice of Intent to Issue PSD Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 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 indicate; (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 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 Department'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.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

Trina L. Vielhauer
Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue PSD Permit (including the Public Notice, 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 10/28/05 to the persons listed:

Roger Fontes, FMPA*
Susan Schumann, FMPA
Mayor, Fort Pierce
Chair, St. Lucie County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Darrel Graziani, DEP SED
Stanley Armbruster, B&V
Hamilton Oven, DEP Siting

Clerk Stamp

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

(Clerk) | 10/28/05 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1110121-001-AC, PSD-FL-353, and PA 05-48

FMPA Treasure Coast Energy Center
Combined Cycle Power Project

St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD Permit) of Air Quality to Florida Municipal Power Agency. The permit is to construct a nominal 300 megawatt (MW) combined cycle electrical power generating plant at the Treasure Coast Energy Center near Fort Pierce, St. Lucie County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400, Florida Administrative Code (F.A.C.), for emissions of particulate matter (PM/PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist, and nitrogen oxides (NO_X). The applicant's name and address are Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida 32819.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 130 MW separate steam-electrical generator, a 170-foot stack, a mechanical draft cooling tower with drift eliminators, a 990,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up ultra low sulfur (ULS) fuel oil (0.0015 percent sulfur) will be burned for a maximum of 500 hours per year.

NO_x emissions will be controlled by selective catalytic reduction (SCR) to achieve 2 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 8 ppmvd while burning ULS fuel oil. Emissions of CO will be controlled to 4.1 and 8 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and ULS fuel oil. Ammonia emissions (NH_3) generated due to NO_X control will be limited to 5 ppmvd.

FMPA's estimates of maximum potential annual emissions from the project are summarized in the following table.

Pollutants	Maximum Potential Emissions Tons Per Year	PSD Significant Emission Rate Tons Per Year
CO	231	100
NO_x	90	40
PM/PM_{10}	176/171	25/15
Sulfuric Acid Mist	22.4	7
SO_2	56.6	40
VOC	23.4	40
Lead	0.007	0.6
Mercury	0.001	0.1
HAPs	12.5	NA

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park and the Chassahowitzka Wilderness Area (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The project has no significant impact on the PSD Class I Chassahowitzka Wilderness and Everglades National Park areas. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 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 indicate; (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 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection	Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southeast District Office	Southeast District Branch Office
111 S. Magnolia Drive, Suite 4	400 North Congress Avenue, Suite 200	1801 SE Hillmoor Dr., Suite C-204
Tallahassee, Florida, 32301	West Palm Beach, Florida 334018	Port St. Lucie, Florida 34952
Telephone: 850/488-0114	Telephone: 561/681-6774	Telephone: 772/398-2806
Fax: 850/922-6979	Fax: 561/681-6755	Fax: 772/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/treasurecoast.htm.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Municipal Power Agency
Treasure Coast Energy Center

300-Megawatt Combined Cycle Power Plant

St. Lucie County

DEP File No. 1110121-001-AC
PSD-FL-353, PA 05-48

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

October 28, 2005

I. APPLICATION INFORMATION

A. Applicant Name and Address

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative: Roger A. Fontes, General Manager and CEO

B. Processing Schedule

April 14, 2005: Received Site Certification Application (SCA) including PSD application

June 6, 2005: Sufficiency determination issued by DEP Siting Coordination Office (SCO) – found insufficient.

July 29, 2005: Received Response to SCO sufficiency questions

August 29, 2005: SCO issues determination finding SCA/PSD Application sufficient

October 28, 2005: Intent to Issue PSD Permit distributed

C. Facility Location

Treasure Coast Energy Center (TCED) will be located in St. Lucie County, southwest of the City of Fort Pierce, East of Highway 95, on Selvitz Road. The site is 180 km from the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area, Everglades National Park. The Chassahowitzka Class I area is 260 km to the Northwest. The UTM coordinates for this site are 561.51 km East and 3028.99 km North. The locations of Fort Pierce and TCEC are shown in Figures 1 and 2.

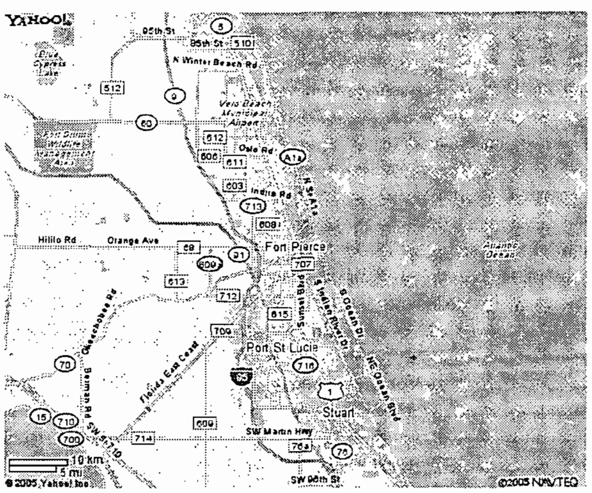


Figure 1. Location of Fort Pierce

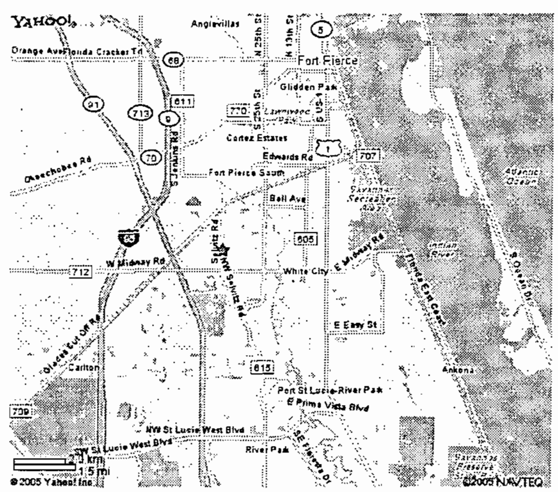


Fig. 2. Location, Treasure Coast Energy Center

D. Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

E. REGULATORY CATEGORIES

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

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

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

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the unit will be subject to Subpart KKKK, and may no longer be subject to Subparts GG. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a major source of HAPs, therefore Unit 1 is not subject to the provisions of 40 CFR Part 63, Subpart YYYY (CT MACT).

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

II. PROPOSED PROJECT SUMMARY

A. PROJECT DESCRIPTION

The applicant proposes to construct a "one-on-one" (1x1) F-Class combined cycle unit (Unit 1) and associated auxiliary equipment. Unit one will consist of one General Electric PG7241 FA combustion turbine generator(CT), a duct-fired heat recovery steam generator (HRSG), and a steam turbine generator (STG) for an overall nominal rating of 300 MW. The key components of the GE MS 7001 FA (a predecessor of the PG 7241 FA) are identified in Figure 3. An exterior view is also shown. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

Auxiliary equipment includes the following: a 990,000 gallon fuel oil storage tank; a diesel engine driven fire pump with an associated 500 gallon fuel oil storage tank, a safe shutdown generator with an associated 1,000 gallon fuel oil storage tank, a mechanical draft cooling tower equipped with drift eliminators, and a 170-foot exhaust stack.

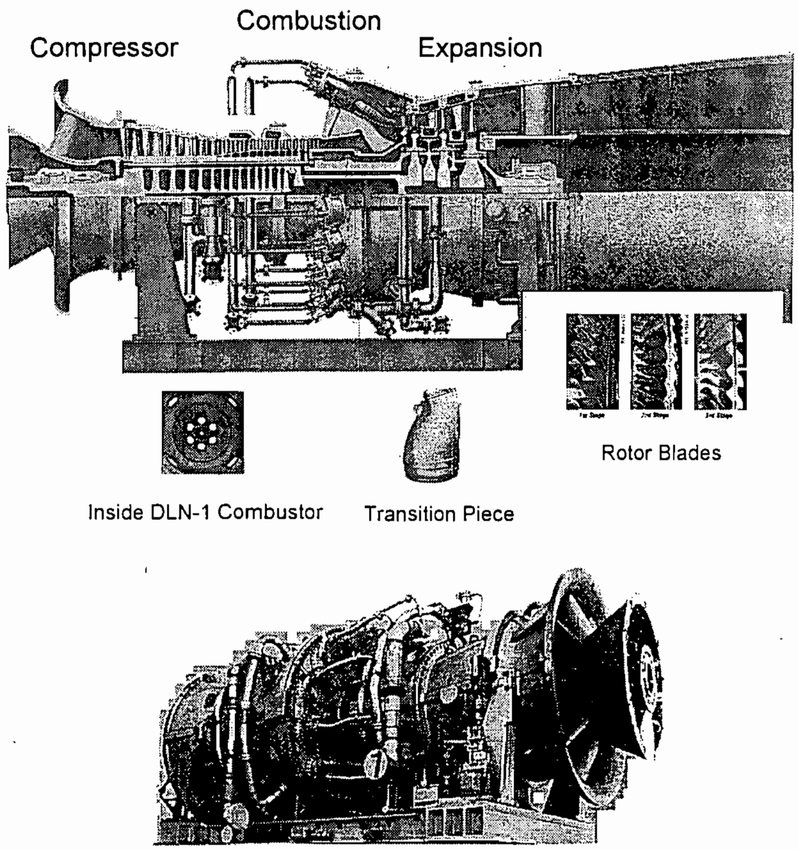


Figure 3 - Internal and External Views of Early GE 7FA

Additional project details, as proposed, are described below.

- Fuel: TCEC will use natural gas as the primary fuel for up to 8760 hours per year, and ultra-low sulfur (ULS) fuel oil (0.0015% Sulfur) as a backup fuel. The applicant requests operation with ULS fuel oil up to 500 hours per year.
- Generating Capacity: The combustion turbine has a nominal generating capacity of 170 MW. The duct-fired HRSG provides steam to the steam turbine electrical generator, which has a nominal capacity of 130 MW. The total nominal generating capacity of the 1 x 1 combined cycle unit is 300 MW.

- Controls: CO and PM/PM_{10} will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ultra low sulfur distillate oil. NO_X emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determination. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The heat recovery steam generator has a combined cycle stack (HRSG stack) that is 170 feet tall with an exit diameter of 18 feet. The following table summarizes the exhaust characteristics at 100 % load and with duct burners on.

Table 1. Exhaust Characteristics of Unit 1 at 100% Load and 26° F

Fuel	Total Heat Input CT + DB (HHV)*	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Exit Temp., °F	Stack Flow ACFM
Gas	2400 mmBtu/hour	26° F	1082° F	167 ° F	1,036,793
ULS F.O.	2597 mmBtu/hour	26° F	1060° F	252° F	1,239,934

*Duct burners account for 523 mmBtu/hour on gas and 553 mmBtu/hour on oil of the total heat input.

B. Process Description

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA (Figure 3) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. Figure 4 is photograph from the GE website of a "7FA on the half-shell" as viewed from the compressor section.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine - section at temperatures of approximately 2500 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature greater than 1000 °F and high excess oxygen and is available for additional energy recovery.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the TCEC project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The key components of a combined cycle unit (without duct firing) are shown in the figure below. The steam is then fed to a separate steam turbine, which also drives an electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent. This equates to a little over 50% on a higher heating value (HHV) basis.

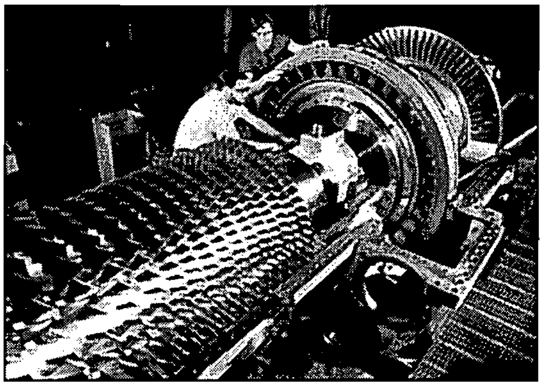


Figure 4 – Internal View - GE 7FA.

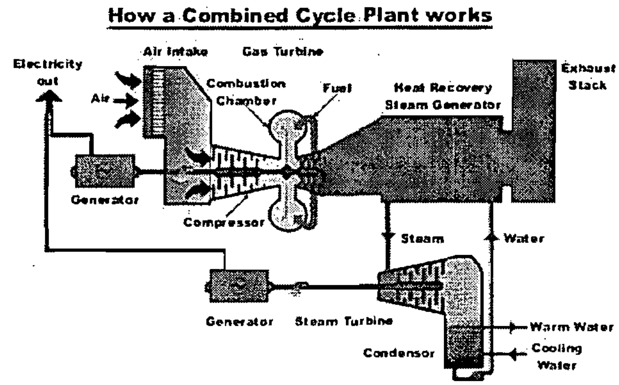


Figure 5. Components Combined Cycle Unit

The applicant has requested the following additional modes of operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging is typically practiced at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests unlimited use of duct burning for the unit while firing either gas or oil in the combustion turbine.

Other possibilities (not requested by FMPA) include power augmentation and peaking. Power augmentation is accomplished by returning a portion of the steam from the HRSG to the combustion turbine to increase mass flow and power output. Peaking is simply running the unit for limited time at heat input values greater than the design rating.

Additional process information related to the combustor design, and control measures to minimize NO_X formation, are given in the draft BACT determination within this evaluation.

C. POTENTIAL EMISSIONS

The project will result in emissions of nitrogen oxides, sulfur dioxides, carbon monoxide, particulate matter, sulfuric acid mist (SAM), volatile organic compounds, lead (Pb), and mercury. The following table summarizes the applicant's estimates of the annual emissions in tons per year from the proposed project. Included in these estimates are emissions from the duct burners, diesel engine fire pump, safe shutdown generator, the fuel oil storage tank for VOCs, and the cooling tower for PM/PM_{10}.

Table 2. Applicant's Estimated Potential Annual Emissions

Pollutant	Project Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required?
NO_x	90.0	40	Yes
SO_2	56.5	40	Yes
CO	228.7	100	Yes
PM	175.9	25	Yes
PM_{10}	171.3	15	Yes
VOC	23.3	40	No
SAM	22.4	7	Yes
Mercury	0.001	0.1	No
Lead	0.007	0.6	No

III. RULE APPLICABILITY

A. STATE REGULATIONS

The 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 following rules in the F.A.C.

Chapter	**Description**
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	Air Pollution Control (Includes Adoption of Federal Regulations)
62-210	Stationary Sources – General Requirements
62-212	Stationary Sources – Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Stationary Sources – Emission Limiting Standards
62-297	Stationary Sources – Emissions Monitoring

B. FEDERAL REGULATIONS

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

Title 40	**Description**
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain – Permits Regulation
Part 73	Acid Rain – Sulfur Dioxide Allowance System
Part 75	Acid Rain – Continuous Emissions Monitoring
Part 76	Acid Rain – Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain – Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

C. DESCRIPTION OF PSD APPLICABILITY REQUIREMENTS

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant; or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.); or
- 5 tons per year of lead.

For new major facilities and modifications at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project as proposed are required for NO_X, SO_2, CO, PM/PM_{10}, and SAM. (Refer to Table 2.)

In addition to a determination of BACT, PSD review also requires an Air Quality Analysis for each pollutant exceeding the SER. The Air Quality Analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

IV. DRAFT DETERMINATION – BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

A. BACT DETERMINATION PROCEDURE

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" – An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

a. *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*

b. *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

1. *Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
2. *All scientific, engineering, and technical material and other information available to the Department.*
3. *The emission limiting standards or BACT determinations of any other state.*
4. *The social and economic impact of the application of such technology.*

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.[1]

B. NO_X BACT DETERMINATION

1. Nitrogen Oxides Formation

Nitrogen oxides form in the combustion turbine process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen.

Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen, also know as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The changes in NO_X production as flame temperatures vary due to increasing/decreasing equivalence ratios can be seen in figure 6 below.

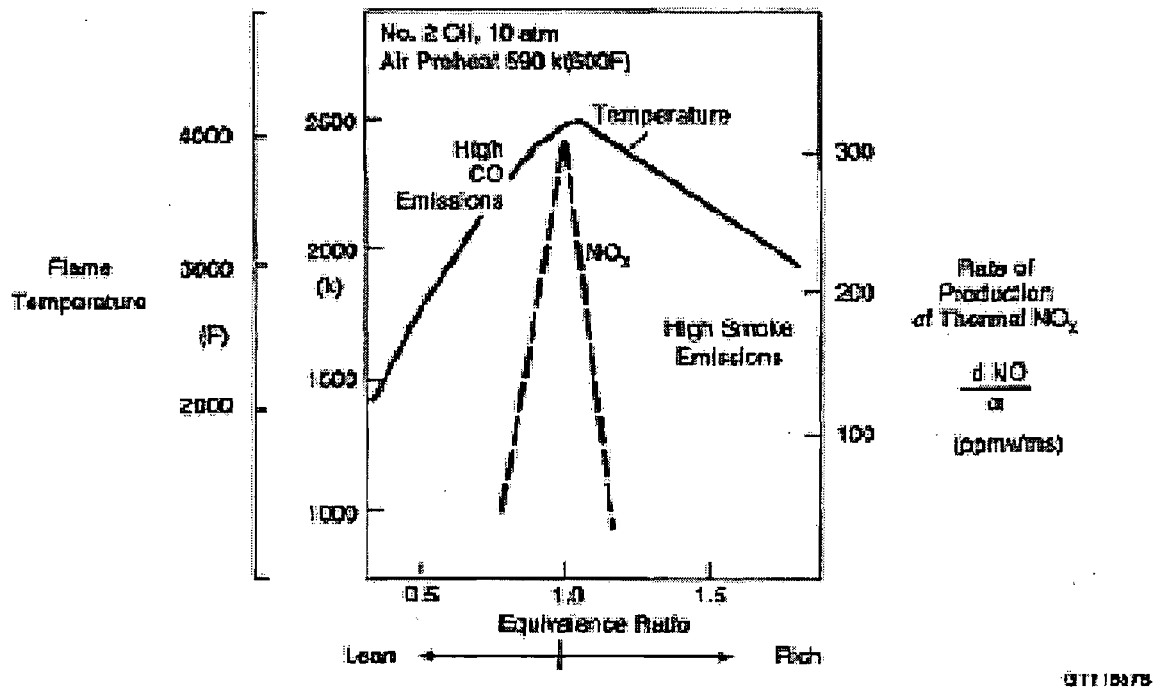


Figure 6 – NO_X Production Rate Variation With Temperature Change[2]

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 7, which is from a General Electric discussion on these principles.

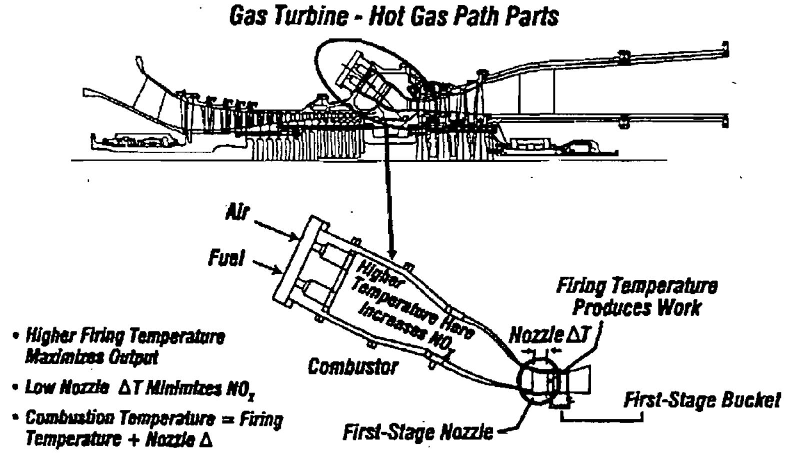


Figure 7 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for a the GE 7FA combustion turbine.[3]

2. Descriptions of Available NO_X Controls

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below.

Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 8.

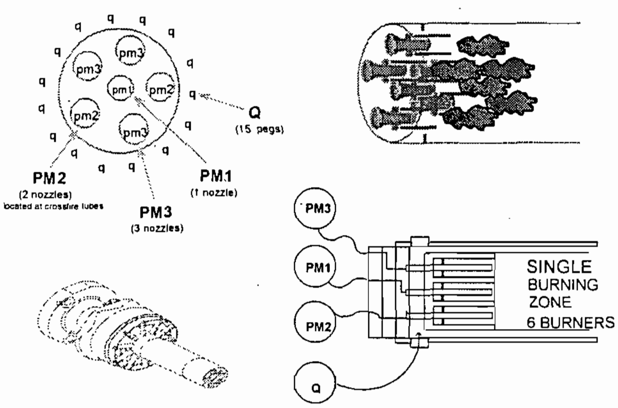
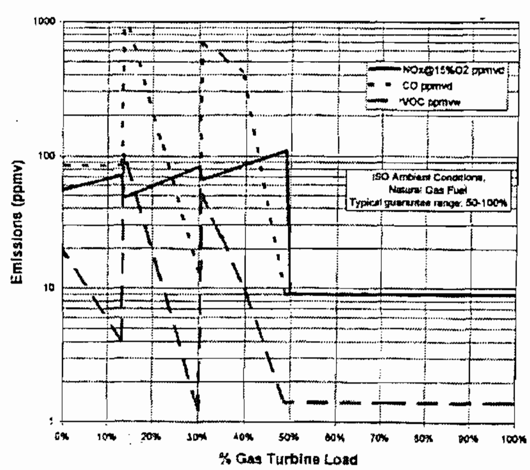


Figure 8 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability. Design NO_X, CO, and VOC emission characteristics of the DLN-2.6 combustor while firing natural gas are given in the graph on the left side of Figure 9 for a unit tuned to meet a 9 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen). The graph on the right hand side is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility.



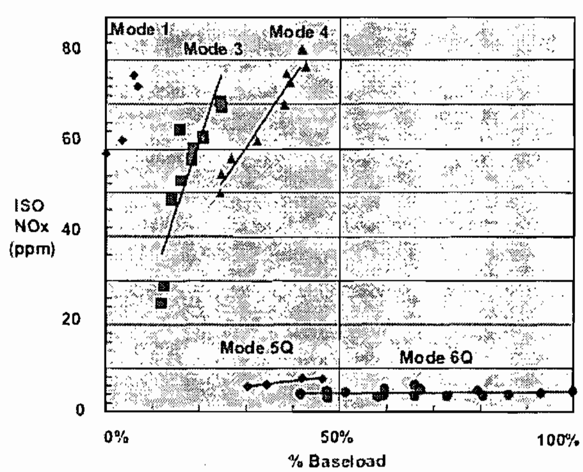


Figure 9 – Emissions Characteristics for DLN-2.6

The combustor emits NO_X at concentrations of 9 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. This suggests the need to minimize operation at low load conditions. The data plot suggests that there is at least a possibility of turndown to less than 50% of full load without excessive emissions.

Note also that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane. Actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[4] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd.

Table 3 – City of Tallahassee Purdom Power Plant (Station Unit 8) Test Results

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

* Not Determined

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[5] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd.

Table 4 – Tampa Electric Polk Power Station Emission Test Results

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

The test results at the Tallahassee and TECO projects confirm NO_X, CO, and VOC emissions less than the emission characteristics published by GE in Figure 9 above. Consistent with the discussion in the previous section, conversations with plant operators indicate that the Low NO_X characteristics extend to operations somewhat less than 50 percent of full load.[6] It is not certain whether low emissions under such operation is guaranteed by GE.

An important consideration in the effort to achieve low NO_X by combustion technology is that power and efficiency are sacrificed. This limitation is seen in Figure 10 from an EPRI report.[7] Developments such as single crystal blading, aircraft compressor design, and high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 10.

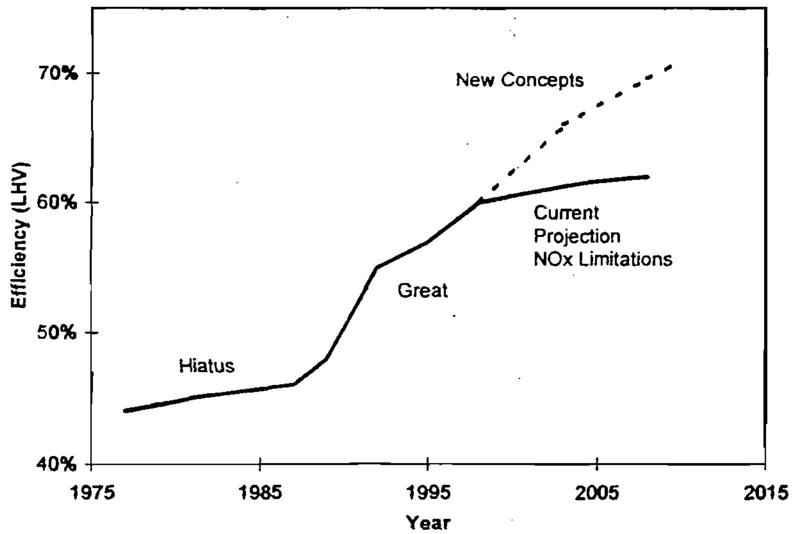


Figure 10 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned for TCEC. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 7). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions and a reduction greater than 90 percent compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_X emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production).[8] Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_X emissions when firing fuel oil as discussed above.

Catalytic Combustion – XONON™. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[9] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[10] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[11] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[12] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the FMPA TCEC project.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$ and

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

There are several examples of conventional SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas, 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TECO Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require conventional SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil.

Figure 11 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 12 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or ultra low sulfur distillate fuel oil. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

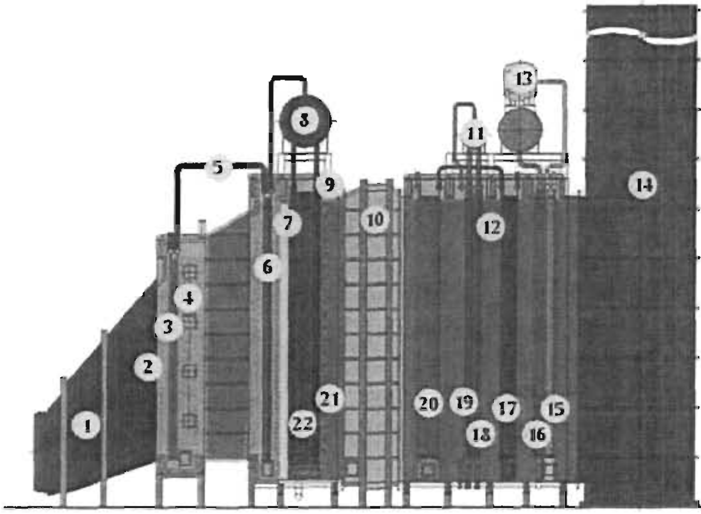


Figure 11 – Key HRSG Components (10 is SCR) Figure 12 – PGN Hines Block I

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.[13] The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 5. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[14]

% Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd	NH_3 ppmvd
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 – 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

It is noteworthy as well that the low NO_X emissions were achieved with minimal ammonia (NH_3) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

<u>$SCONO_X$™</u>. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions

using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

$SCONO_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[15] None were installed at large facilities.

$SCONO_X$™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. $SCONO_X$™ can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

Table 6 contains averaged cost values for $SCONO_X$™ and SCR developed by the California Air Resources Board for their Legislature.[16] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 6. Cost Comparison between SCR and $SCONO_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X$™	SCR/CO	$SCONO_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with $SCONO_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the $SCONO_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by FMPA for the proposed 300 MW project claim even greater annual cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that $SCONO_X$™ is not cost-effective for the present project.

3. Applicant's NO_X BACT Proposal

The applicant determined that BACT for proposed Unit 1 NO_X control, is the use of SCR in conjunction with Dry Low NO_X burners while firing natural gas, and SCR with water injection while firing ultra low sulfur fuel oil. Fuel oil use will be limited to 500 hours per year or less.

The applicant proposed the following BACT limits for NO_X:

- Gas Firing: 2.0 ppmvd @ 15% O_2
- Oil Firing: 8.0 ppmvd @ 15% O_2

Note: No averaging times are specified in the application.

4. Department's Draft NO_X BACT Determinations

Table 7 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average.

The Department agrees that FMPA's proposal of 2.0 ppmvd @15% O_2 with an averaging period of 24-hrs, and minimization of fuel oil use represent BACT for this project. The limits of 2.0 and 8.0 ppmvd @15% O_2, represent reductions of 98% and 92% for the gas and oil cases respectively when compared with the New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 7. Recent NO_X Standards for F-Class Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2, Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Towantic Energy , CT	540	2.0 NG (1-hr) 5.9 – FO	2 GE 7FA
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4x160 MW GE 7FA &DBs
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 – FO	4x170 MW GE 7FA & DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Summit Vineyard, UT	560	2.0 – NG (3-hr)	2 WH501F & DBs
Pacificorp Currant, UT	525	2.25 – NG (3-hr)	2 GE 7FA & DBs
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 – FO	4x170 MW GE 7FA & DBs
PGN Hines III, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
PGN Hines IV, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs

Notes: NG = Natural Gas; DB = Duct Burner; PA = Power Augmentation; FO = Fuel Oil; GE = General Electric; WH = Westinghouse; ABB = Asea Brown Bovari

C. CO BACT DETERMINATION

1. CO Formation and Control Options

Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most combustion turbines incorporate good combustion practices based on high temperature, sufficient time, turbulence, and excess air to minimize emissions of CO. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are typically reported for very large combustion turbines (at least at full load operation) without use of oxidation catalyst.

Based on testing discussed in the NO_X technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring (CEM) requirements for CO. Continuous data from these units verify the ability of the 7FA to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO CEMS data recorded at TECO Bayside for 4 GE7FA units is shown in Table 8 below.

Table 8. CO CEMS Data – TECO Bayside Unit 1.

Turbine	Quarter	CO Max 24-hr Block (ppmvd)	CO Min 24-hr Block (ppmvd)	CO Quarterly Average (ppmvd)
1A	3rd Quarter 2003	4.3	0.3	0.83
1B		1.7	0	1
1C		2.1	0	0.8
1A	4th Quarter 2003	2.2	0	0.76
1B		1.9	0	1.14
1C		1.2	0	0.74

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE 7FA. Performance guarantees are only now "catching up" with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[17] The following statement was taken from the report:

"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation – thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

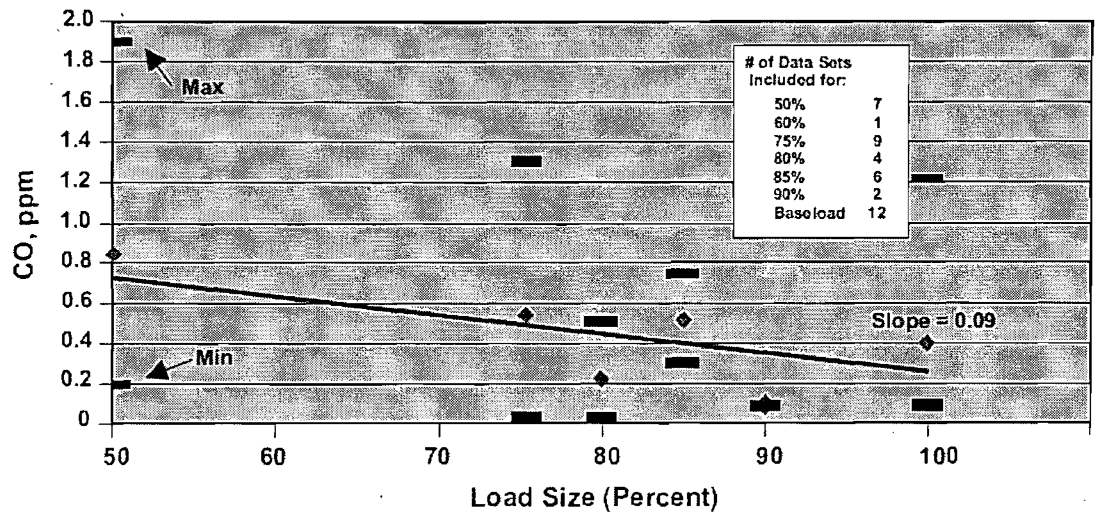


Figure 13. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

2. Duct Burner and Fuel Oil Considerations

The proposed unit includes a HRSG equipped with supplemental duct firing. Turbine exhaust gas (TEG) is reheated with a gas-fired duct burner prior to entering the heater. Key HRSG components are shown in Figure 11. TEG enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O_2). In the design shown, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6).

Figures 14 and 15 are of an individual burner and a HRSG under construction showing horizontal duct burner elements and flow baffles. The hot TEG serves as combustion air for gas introduced into the burner array. The ignition temperature for CO is between 1,100 and 1,200 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG.

Certain configurations (NovelEdge™) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC control because of destruction by the duct burner.[18] Basically, the claim is that a "3 on 1" configuration (3 CT's & 1 HRSG) producing 750 MW can be replaced with a "2 on 1" configuration by adding very large Coen "Power Plus" DBs in a Nooter Eriksen HRSG and still produce 750 MW. The capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided.

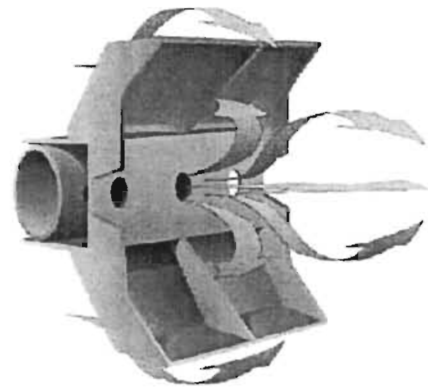


Figure 14 – Individual Burner

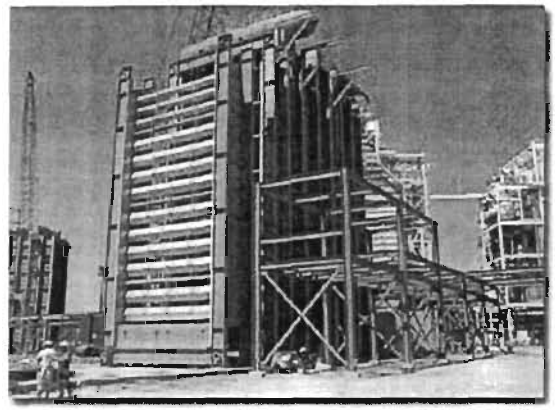


Figure 15 – Duct Burner and HRSG (Coen)

Following is a table with the results of CO and VOC testing completed at the Gulf Power Lansing Smith Plant[19] and the Southern/KUA/OUC/FMPA project at OUC Stanton. The units are GE7FA combustion turbines (CT) of the same type that will be installed at the TCEC. Tests were conducted on each combustion turbine while using duct burners (DB). CO emissions increase slightly when firing duct burners, but still remain very low. No appreciable differences in CO emissions are noted for large combustion turbines when operating on fuel oil versus natural gas.

Table 9. CO and VOC Emissions while Duct Firing – GE 7FA Units (ppmvd @15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
OUC Stanton Unit 25 (CT)	0.5	0.04
OUC Stanton Unit 26 (CT)	0.5	0.49
OUC Stanton Unit 25 (CT & DB)	1.6	0.2
OUC Stanton Unit 26 (CT & DB)	1.6	0.26

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in Table 10 below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_X control is practiced on all such units when firing fuel oil. The Department concludes that the low CO and VOC emissions while burning fuel oil are characteristics of the GE 7FA combustion turbines such as FMPA proposes to install at the TCEC.

Measured CO and VOC emissions were also low during a test of a GE 7FA combined cycle unit (permitted in 1999) while firing fuel oil and using a gas-fired duct burner. The results are given in the Table 11. FMPA does not propose fuel oil firing while using gas-fired duct burners. However this case is relevant because it combines the two modes for which FMPA requests additional emissions considerations. Even this special case indicates a reasonable expectation of low CO emissions.

Table 10. CO, VOC Results. GE 7FA Gas Turbines firing Fuel Oil. (ppmvd @15% O_2)

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)[20]	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
Purdom Unit 8 (~50%)[21]	1.2	
Purdom Unit 8 (100%)	1.3	
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)[22]	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)[23]	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

Table 11. Emissions – GE 7FA CT, Fuel Oil & Gas-Fired Duct Burner (ppmvd @15% O_2)

KUA 3/Mode[24]	NO_X	CO	VOC	NH_3
CT & DB & FO	15	1.4	0.1	1.5

3. Low Load Considerations

The full DLN features of the DLN 2.6 operate at loads greater than 50%. For that reason, the Department and most other regulatory agencies typically disallow operation at less than 50% load in most of the permits they issue for combustion turbines. In some cases the prohibition applies even at greater loads based on the features of the combustors.

FMPA personnel indicated that the proposed unit will often be operated at less than full load and that a higher CO BACT limit would be warranted. Figure 16 is a data plot from a GE publication showing how CO actually varies with respect to load. The data suggest that there is some turndown capability while emitting 7 or less ppmvd CO. This value is equal to approximately 5 to 6 ppmvd @15% O_2. The similar plot in Figure 9 suggested that NO_X emissions can also be maintained at low loads between 30 and 50% for both Modes 5Q (5 nozzles in operation) and 6Q (6 nozzles in operation), but not for Mode 4.

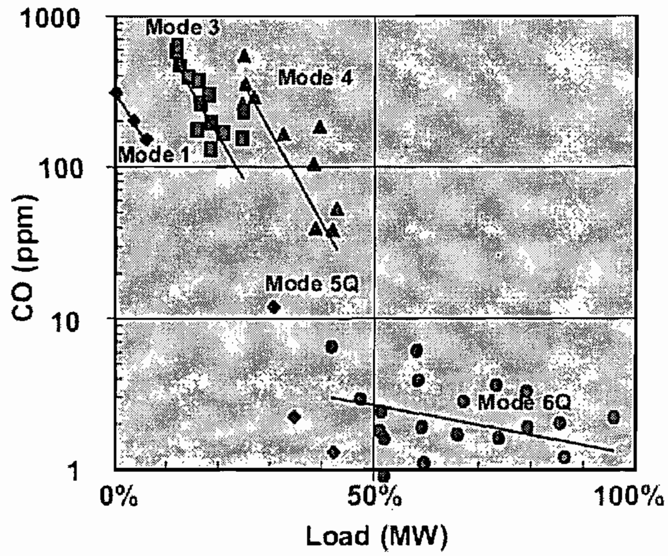


Figure 16 – Emissions Characteristics for DLN-2.6

The unit would need to operate in Mode 6Q which means that all six fuel nozzles and quaternary pegs are in operation. There is some suggestion that low CO can be maintained while operating in Mode 5Q, which is like 6Q, but without using the center nozzle. The manner by which the unit is ramped up through Modes 1, 2, 4, 5Q and 6Q and then backed down to low load cannot be inferred by this diagram. Flame stability of DLN conditions at low load is complex, and will not be addressed here.

The Department obtained data from operations at JEA Brandy Branch.[25] They are summarized in the following table. For reference 65 MW represents roughly 38% of full load. According to the utility, GE offers the software to tune and operate under the described conditions. A utility representative said that the unit operated in Mode 6Q during the tests.[26]

Table 12. CO Emissions during Low Load Operation at JEA Brandy Branch Unit 1

Test/Run	Load (MW)	Load (% full load)	CO (ppm)	CO (ppm) @15%O_2)
1/1	65	38	9.6	8.5
1/1	65	38	9.0	8.0
1/3	65	38	9.2	8.1
2/1	65	38	12.2	10.7
2/2	65	38	12.2	10.7
2/3	65	38	11.9	10.5
3/1	65	38	12.3	10.9
3/2	65	38	11.9	10.5
3/3	65	38	12.1	10.6

4. Applicant's CO BACT Proposal

The applicant has proposed BACT for CO as the use of good combustion controls while firing natural gas or ULS in accordance with the defined operating hours for each fuel. FMPA concluded that oxidation catalyst for the removal of CO is not cost effective. In the response dated July 28 to the Department's Notice of Insufficiency, FMPA requested the BACT limit for CO be set at 8.0 ppmvd while firing natural gas and 12.0 ppmvd while firing fuel oil based on 24-hr block averaging times.

Table 13 below contains the emissions guarantees for CO submitted to the Department by FMPA for the TCEC project. The values are "uncorrected". For reference the value of 5 ppmvd equates to approximately 4.1 ppmvd @15% O_2. Similar corrections apply to the other values cited.

Table 13. CO Guarantee Information Submitted by FMPA

Fuel	CO Guarantee (ppmvd)	Load Range (%)	Ambient Range (°F)
Natural Gas	5.0	50 - 100	35 - 85
Natural Gas	5.0	60 - 100	>85 - 100
Natural Gas	9.0	50 - <60	>85 - 100
Natural Gas	9.0	50 - 100	26 - <35
Fuel Oil	8.0	75 - 100	26 - 100
Fuel Oil	20.0	50 - <75	26 - 100

The guaranteed value for CO emissions is 5 ppmvd (4.1 ppmvd @15% O_2) while burning natural gas at loads between 60 and 100 percent. A higher limit of 9 ppmvd is guaranteed for very low temperature conditions that are infrequent at the proposed site. The same value is proposed when the ambient temperature is greater than 85 °F.

The Department has no data to support the need for the greater value at higher temperatures. Actually at such temperatures, the inlet air will be subjected to evaporative cooling and operation will simulate normal temperature ranges. Also, if the unit is operated at a higher heat input rate to try to recover some of the lost power at high ambient temperature, the firing temperature will increase and CO will probably decrease.

A limit of 8 ppmvd is guaranteed while burning fuel oil. However, according to Table 10 above, CO emissions while burning fuel oil are actually very low, even at 50 percent of full load. There does not appear to be a solid basis for the relatively high 20 ppmvd guaranteed value between 50 and 75 percent of full load.

5. Department's Draft CO BACT Determinations

Table 14 includes some recent BACT determinations for CO (and VOC and PM) in Florida and other states. FMPA's proposal is included for comparison. Most of the projects cited required oxidation catalyst. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

Table 14. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units

Project Location	CO - ppmvd (@15% O_2)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	0.008 (NH_3 = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	0.01
Duke Morro, CA	2.0 (Ox-Cat)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
FPL Turkey Pt., FL	4.1 – NG (DB off, AnnualTest) 7.6 – NG (DB on, Annual Test) 14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
FMPA TCEC, FL	8.0 NG (24-hr block) 12.0 FO (24-hr block)	38.0 lb/hr – NG (front + back ½) 52 lb/hr – FO (front + back ½)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	0.011
Calpine OEC, PA	10 (1-hr)	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	10% Opacity NH_3 = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5
PGN Hines IV, FL	8.0 - NG 12.0 – FO	10% Opacity NH_3 = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	10% Opacity

Notes: NG = Natural Gas; DB = Duct Burner; PA = Power Augmentation
FO = Fuel Oil; GE = General Electric; WH = Westinghouse; ABB = Asea Brown Bovari

With oxidation catalyst a GE 7FA will likely achieve CO values much less than 2 ppmvd @15% O_2. The actual performance would likely be as good or better than the GT-24 example given in Table 5. That unit had CO characteristics ranging from ~0 to 0.8 ppmvd @15% O_2 at 50% or more of full load. Although the GE 7FA will be guaranteed to achieve 5 ppmvd (4.1 ppmvd @15% O_2), the data suggest typical emissions without oxidation catalyst that are approximately equal to the emission limit of 2 ppmvd @15% O_2 given above as "Top" control.

If the unit fired only natural gas and did not experience the other operating modes, it would be straightforward to conclude that the cost of oxidation catalyst would not be justified because the cost to reduce "permitted emissions" from 5 to 2 ppmvd @15% O_2 would not be cost-effective. This is in agreement with the conclusion in the GE paper cited in the discussion leading to Figure 13 above.

Notwithstanding the guarantees given in Table 13, the data available to the Department suggests that CO emissions from the GE 7FA are also inherently low for the duct firing and fuel oil use modes. They are also inherently low to loads equal to 50%. At loads less than 50%, they can be maintained close to 10 ppmvd @15% O_2 while operating the unit with natural gas and in the 5Q or 6Q DLN modes. Some consideration can be given for the time that the unit will actually operate in those modes, in the same manner as consideration is given to increased CO emissions from limited power augmentation at other projects.

BACT for CO is determined to be the 5.0 ppmvd (4.1 ppmvd @ 15% O_2) for natural gas firing and the 8.0 ppmvd (7.6 ppmvd @ 15% O_2) for fuel oil firing. A continuous limit of 8.0 ppmvd @15% O_2 on a 24-hour basis will be implemented for both gas and oil firing, with or without the duct burner in operation.

An annualized limit of 6 ppmvd @15% O_2 will also be included in recognition of the preponderance of the time when the unit will be operated in the normal natural gas mode and the reality that most modes are characterized by inherently low emissions.

The limited time during which the unit will be operated at low load can be accommodated within this limit based on the data presented above. If extensive operation at loads less than 50% is foreseen, then the situation described in the GE paper would revert to the case where oxidation catalyst is indicated. In that case, CO emissions of 10 ppmvd or greater could be controlled to 2 ppmvd or less by oxidation catalyst.

The Department's BACT determination is the same as that issued for the FPL Turkey Pt. Project. The impacts of the modes (beyond the simple case of natural gas use at 50-100% load) are about equal for the two projects. In contrast to permits for other facilities in Florida and other states, it will not be necessary to prohibit low load operation because the behavior of emissions at lower loads is no longer unknown. Emissions limits can still be met with some operation between 40 and 50 % load.

For reference, FMPA estimated the cost of CO removal by oxidation catalyst to be approximately $3,400 per ton. While the Department does not necessarily agree with this estimation, oxidation catalyst would not be cost-effective for this unit given that the Department's BACT determination is implemented.

In summary, the Department will set the following BACT limits:

- Gas Firing: 8.0 ppmvd @ 15% O_2 (24-hr average)
  Without DB: 4.1 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr limit)
  With DB: 7.6 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr limit)
  Low Load: (included in 24-hr limit)
- Oil Firing: 8.0 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr average)
- All Modes: 6.0 ppmvd @ 15% O_2 (12-month average)

D. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

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

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution to the market.

For this project, the applicant has proposed as BACT, for SO_2 and SAM, the use of pipeline natural gas and limited use (500 hrs or less) of ultra low sulfur diesel fuel oil with less than 0.0015 percent sulfur by weight as BACT. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8 percent by weight.

E. Particulate Matter (PM/PM_{10}) BACT Determination and Ammonia (NH_3) Control

1. PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ultra low sulfur fuel oil are efficiently combusted in gas turbines and will be the only fuels fired in the proposed unit. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ULS fuel oil to be combusted contains a minimal amount of ash and will be used for less than 500 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

2. Other PM/PM_{10} Considerations

Ammonia Slip and Ammonium Salts Formation: Emissions of NO_X, SO_2, and SAM are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. Because PM/PM_{10} emissions can be increased due to the formation of these ammonium salts prior to exiting the stack, it is important to limit ammonia emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of ammonia slip can also be an indication of a degrading catalyst. The Department proposes an ammonia limit of 5 ppmvd @ 15% O_2.

Cooling Tower PM Emissions: Small amounts of water entrained in the air passing through a wet cooling tower can be carried out of the tower and are known as "drift" droplets. Because the droplets contain impurities from the cooling water, the particulate matter constituent of the drift droplets may be classified as an emission[27]. The amount of particulates that may be emitted are based on the solids loading in the re-circulating water.

The applicant's proposal includes an 8-cell, 111,130 gallon per minute (gpm) mechanical draft cooling tower with drift eliminators with a design drift rate of 0.0005% of design water flow. FMPA estimates annual PM and PM_{10} emissions from the cooling tower to be 6.48 TPY and 1.87 TPY respectively.

3. Applicant's PM/PM_{10} Proposal

The applicant determined that BACT for proposed Unit 1 PM/PM_{10} is good combustion controls and the use of good natural gas, ultra low sulfur fuel oil.

4. Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbine may fire distillate oil as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd.
- The cooling tower shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

The Department notes that the described measures minimize emissions and formation of fine particulate matter classified as $PM_{2.5}$. The described strategy directly reduces PM emissions as well as formation of ammoniated particulate matter. Finally the NO_X and SO_2 control minimizes emissions of precursors known to contribute to formation of $PM_{2.5}$ in the environment.

F. BACT CONSIDERATIONS FOR AUXILIARY EQUIPMENT

Safe Shutdown Generator: The safe shutdown generator (an approximately 765 hp diesel engine) will be used when the transmission connection to the plant is lost. The generator will be operated to provide power to the plant in a safe shutdown condition when needed, and for periodic testing throughout the year to ensure operability.

Diesel Engine Fire Pump: The diesel engine fire pump (an approximately 300 hp diesel engine) falls under the categorical emission unit exemption for fire and safety equipment (Rule 62-210.300(3)(a)22, F.A.C.) Like the safe shutdown generator, the fire pump will be operated only during emergency situations and for periodic testing throughout the year.

Use of ultra low sulfur fuel oil and limited operation (200 hours or less) ensure that emissions from both the safe shutdown generator and the diesel engine fire pump will be minimal. However, projected potential emissions from both units are included in the project potential to emit calculations and the ambient air quality impact analysis.

G. Summary of Department Draft BACT Determination

Emissions from the gas turbine shall not exceed the values given in the following table.

Table 15. Draft BACT Determination – Treasure Coast Energy Center Unit 1

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
		CT, Low Load	NA	NA	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10} [c]	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using a HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

V. NEW SOURCE PERFORMANCE STANDARDS

A. COMBUSTION TURBINES

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (gas) ≤ 109 ppmvd @ 15% O_2 (corrected for heat rate of 9,355 Btu/KW-h LHV at peak load, evaporative cooler on) and;
- NO_X (oil) ≤ 101 ppmvd @ 15% O_2 (corrected for a heat rate of 10,120 Btu/KW-h LHV at peak load, evaporative cooler on); and
- SO2 emissions are limited to < 0.015 percent by volume at 15% O2 on a dry basis (150 ppmvd) or by the use of a fuel with a sulfur content of no more than 0.8% by weight (8000 ppmw).

A more recent standard was proposed by EPA on February 18, 2004. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (gas) ≤ 0.39 lb/megawatt-hour. This is approximately equal to 11 ppmvd @15% O_2 for this turbine.
- NOX (oil) ≤ 1.2 lb/megawatt-hour. This is approximately equal to 33.5 ppmvd @15% O_2 for this turbine.
- SO2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% (500 ppmw) by weight.

The final rule will be applicable to TCEC Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

The Department considers the draft BACT standards more stringent than the existing or the proposed NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

B. DUCT BURNERS

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 554 MMBtu per hour (HHV). This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NO_X ≤ 1.6 lb/MW-hr (gross)

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.1 lb/MW-hr for NO_X. This will insure that the NSPS NO_X emission limit for the duct burners will easily be met. For example, if emissions from a duct burner alone exceeded its NSPS standards, then emissions from the duct burner and associated combustion turbine combined would exceed the BACT limits. An Appendix to the permit will summarize applicable federal requirements.

VI. PERIODS OF EXCESS EMISSIONS

A. Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

B. Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "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." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup, up to four hours of excess emissions are allowed. "Warm startup" is defined as a startup following a shutdown lasting between 8 and 48 hours.
- For cold startup to combined cycle operation, up to six hours of excess emissions are allowed. "Cold startup" is defined as a startup following a shutdown lasting at least 48 hours.
- For shutdown, up to three hours of excess emissions are allowed.

- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are generally infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

<u>DLN Tuning</u>: Dry Low NOX combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NOX and CO emissions, and extends the life of the unit components. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Excess emissions of NOX, CO, and opacity are allowed during DLN tuning sessions provided the proper notification is provided to the Compliance Authority. Notification two weeks prior to tuning will be required.

<u>Combined Cycle Operation with Dump Condenser</u>: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

VII. AIR QUALITY IMPACT ANALYSIS

A. INTRODUCTION

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2 and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM.

B. MAJOR STATIONARY SOURCES IN ST. LUCIE COUNTY

The current largest stationary sources of air pollution in St. Lucie County are listed below. The information is from annual operating reports submitted to the Department.

Table 16. MAJOR SOURCES OF NO_X IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Calpine	***Blue Heron Energy Center (proposed)***	***313***
Florida Gas Transmission (FGT)	FGT Station 20	261
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***91***
Tropicana Products	Tropicana Products	45
Fort Pierce Utilities Authority	HD King Power Plant	30

Table 17. MAJOR SOURCES OF SO_2 IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Calpine	***Blue Heron Energy Center (proposed)***	**226**
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***58***
Dickerson Florida, In	Dickerson/Asphalt Plant #14	10

Table 18. MAJOR SOURCES OF PM/PM_{10} IN ST. LUCIE COUNTIES (2003)

Owner/Company	Site Name	Tons per year
Calpine	***Blue Heron Energy Center (proposed)***	**264**
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***176***
Tropicana Products	Tropicana Products	22
Cargill Juice North America	Ft. Pierce	9

Table 19. MAJOR SOURCES OF CO IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***234***
Tropicana Products	Tropicana Products	169
Cargill Juice North America	Ft. Pierce	160
Calpine	***Blue Heron Energy Center (proposed)***	**156**
Florida Gas Transmission (FGT)	FGT Station 20	111

C. AIR QUALITY AND MONITORING IN ST. LUCIE COUNTY

The Southeast District in West Palm Beach operates four monitors at one site in St. Lucie County measuring PM_{10}, $PM_{2.5}$, ozone, and NO_2. The monitoring site is shown in the figure below.

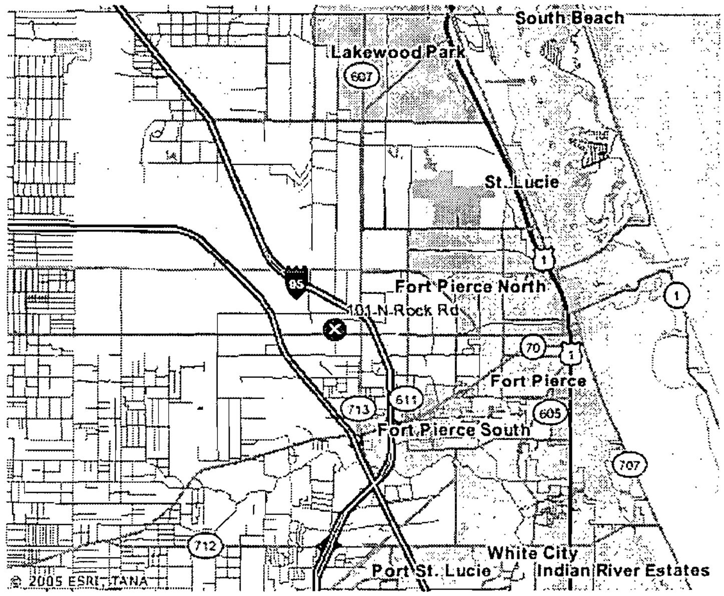


Figure 17. St. Lucie Monitoring Site

Measured ambient air quality information is summarized in the following table.

Table 20. Ambient Air Quality Nearest to Project Site (2003)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Ft. Pierce	24-hour	65	43		150 [a]	ug/m³
		Annual			17	50 [b]	ug/m³
SO_2	Riveria Beach	3-hour	4	3		500 [a]	ppb
		24-hour	2	2		100[a]	ppb
		Annual			1	20 [b]	ppb
NO_2	Ft. Pierce	Annual			9	53 [b]	ppb
CO	West Palm Beach	1-hour	5	4		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Ft. Pierce	1-hour	0.081	0.076		0.12 [C]	ppm
		8-hour	0.071	0.071		0.08 [C]	ppm

a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period

St. Lucie County/The Southeast District does not monitor for Sulfur Dioxide or Carbon Monoxide. Therefore the data for these pollutants are not representative of air quality near the proposed plant site. However, measurements at sites throughout the state that are in the vicinity of larger SO_2 and CO sources than the proposed plant are also in attainment with the respect to the SO_2 and CO NAAQS. Therefore it is reasonable to conclude that SO_2 and CO concentrations near the project site are also in attainment of the SO_2 and CO NAAQS.

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels. The exception is ozone because it is formed from precursors that are clearly available (NOX and VOC). The precursors are more available during drought years. The tendency to form ozone is accentuated by hot ambient temperature, high pressure, and relatively low wind speed.

D. AIR QUALITY IMPACT ANALYSIS

1. Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I (Everglades National Park - ENP and the Chassahowitzka National Wildlife Refuge -CNWR) and PSD Class II Areas (everywhere except the Class I areas).

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all facilities or projects in the area (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 21. Maximum Projected Air Quality Impacts from Treasure Coast Energy Center Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	Baseline Concentrations (ug/m3)	Ambient Air Standards (ug/m3)	Significant Impact?
SO_2	Annual	0.1	1	~3	60	NO
	24-Hour	1	5	~5	260	NO
	3-Hour	3	25	~10	1300	NO
PM_{10}	Annual	0.2	1	~17	50	NO
	24-Hour	4.2	5	~65	150	NO
CO	8-Hour	17	500	~2300	10,000	NO
	1-Hour	27	2000	~5750	40,000	NO
NO_2	Annual	0.1	1	~17	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 180 km to the south-southwest west of the project site. The CWNR is located about 260 km to the northwest of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from SO_2, PM_{10}, and NO_2 are less than the applicable SILs for the Class I areas. Therefore no further detailed modeling efforts are required.

Table 22. Maximum Air Quality Impacts from the Treasure Coast Energy Center Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.003	0.2	NO
	24-hour	0.05	0.3	NO
NO_2	Annual	0.001	0.1	NO
SO_2	Annual	0.0005	0.1	NO
	24-hour	0.01	0.2	NO
	3-hour	0.03	1	NO

The Maximum Air Quality Impacts for comparison to the PSD Class I SILs at CWNR are less than the impacts at ENP.

2. Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 23. Maximum Air Quality Impacts vs. the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~65	NO
NO_2	Annual	0.1	14	~17	NO
SO_2	24-hour	1	13	~5	NO
CO	8-hour	17	575	~2300	NO

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

3. Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from West Palm Beach. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP and CWNR beyond 50 km from the proposed project. Meteorological data used in this model was from the National Weather Service West Palm Beach as with the ISCST3 model.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

E. Additional Impacts Analysis

1. Impact on Soils, Vegetation, and Wildlife

Very low emissions are expected from the natural gas and distillate oil fired gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS.

Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife will be minimal or insignificant.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I areas. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are less than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

According to the applicant, the maximum predicted deposition rates were located in the ENP. The impacts of the deposition rates of sulfur and nitrogen, 0.00051 and 0.00097 kg/ha/yr respectively, are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

The low NO_X limit coupled with the use of ultra low sulfur fuel oil and inherently clean natural gas will minimize any possible effects due to sulfur and nitrogen deposition. Additionally the fuels are extremely low in mercury content. The very low sulfur deposition rate from the proposed project will also minimize activation of mercury in the soils by sulfur reducing bacteria.

The National Park Service and Fish and Wildlife Service do not anticipate any significant impacts with regards to AQRV's in the ENP and CWNR from the proposed project.

2. Impact on Visibility and Regional Haze

The applicant submitted a regional haze analysis for the ENP and CWNR. The analysis included modeling from the CALPUFF model. The CALPUFF model predicts modeled impacts well below the 5% visibility impairment based on criteria from the NPS.

The National Park Service and Fish and Wildlife Service do not anticipate any significant visibility impacts in the ENP and CWNR from the proposed project.

3. Growth-Related Impacts Due to the Proposed Project

There will be short-term increases in the labor force to construct the project. According to the applicant, about 286 additional workers will be needed over the 11-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the project will require 16 new permanent employees, which will cause no significant impact on the local area.

4. Growth-Related Air Quality Impacts since 1977

According to the applicant, St. Lucie County is the 3rd fastest growing county in Florida. Residential growth in the area of the proposed project, St. Lucie County, has nearly tripled from 1977 to 2005. The county has continued to be in attainment with all National Ambient Air Quality Standards.

5. Endangered Species Considerations

The purpose of the Endangered Species Act (ESA) is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.[28] Under the law, species may be listed as either "endangered" or "threatened".

Endangered means a species is in danger of extinction throughout all or a significant portion of its range. Threatened means a species is likely to become endangered within the foreseeable future. All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened.

While state PSD permits are not generally reviewed for adherence with the Endangered Species Act, the State of Florida's Power Plant Certification process requires an assessment of existing ecology and determination of project impacts. Sections 2.3 and 4.4 of the Site Certification Application include a characterization of the existing environment, and an ecological impacts assessment including wildlife and threatened and endangered species. The applicant concludes that the project will not have an adverse effect on endangered species.

According to the U. S. Fish and Wildlife Service (F&WS) website there were 111 threatened or endangered species (per the federal list) in Florida on May 18, 2004.

The reader is referred to the following website:

http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=FL

Threatened and endangered animal species observed within a five mile radius of the TCEC site include several bird species such as the bald eagle, the Florida sandhill crane, and the snail kite. The Sherman's fox squirrel and eastern indigo snake have also been observed within this area. According to the application, there are no federal or Florida listed threatened or endangered species known to occur on the site or in close proximity. There is one bald eagle nest, however northwest of the site, of which the exact location is not known. The bald eagle is protected in accordance with the Endangered Species Act, Bald and Golden Eagle Protection Act, and the guidance document entitled *Habitat Management Guidelines for the Bald Eagle in the Southeast Region*, issued by the U.S. Fish and Wildlife Service. FMPA has committed to consulting the U.S. Fish and Wildlife Service on how to best avoid disturbing the nest during site development and operation.

Figure 18. Nesting Eagle in South Florida

Figure 19. Eagle Pair in SW Florida

FMPA has already contacted both the U.S. Fish and Wildlife Service and the Florida Fish and Wildlife Conservation Commission by letter requesting review of the proposed project.[29, 30]

VIII. 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 PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Cindy Mulkey is the project review engineer and is responsible for preparing the draft permit conditions. She may be contacted at cindy.mulkey@dep.state.fl.us and 850-921-8968. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the Section Adminstrator. He reviewed, contributed to and affixed his seal on this Techncial Evaluation and Preliminary Determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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PERMITTEE:

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative:
Daniel Cassel, Director of Generation

Treasure Coast Energy Center
DEP File No. 1110121-001-AC
Permit No. PSD-FL-353
SIC No. 4911
Expires: July 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 300 MW gas-fired combined cycle electrical power plant. The project will include one 170 MW combustion turbine generator, one heat recovery steam generator, a 130 MW steam turbine generator, a fuel oil storage tank, a mechanical draft cooling tower, and auxiliary equipment. The project will be located southwest of the city of Fort Pierce, East of Highway 95 in St. Lucie County.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendices are made a part of this permit:

Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determination and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements
Appendix GC	Construction Permit General Conditions
Appendix GG	NSPS Subpart GG Requirements
Appendix SC	Standard Conditions

Michael G. Cooke, Director
Division of Air Resources Management

Date:______________

FACILITY DESCRIPTION

The proposed FMPA facility is a combined cycle power plant. The project is to install one combined cycle unit which will consist of one gas turbine (nominal 170 MW) and one heat recovery steam generator with supplementary duct firing, a steam turbine-electrical generator (nominal 130 MW), a mechanical draft cooling tower, and one 990,000 gallon fuel oil storage tank. Ancillary equipment includes a diesel engine driven fire pump with associated 500 gallon fuel oil tank, and a safe shutdown generator.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions unit:

EU ID NO.	EMISSION UNIT DESCRIPTION
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

REGULATORY CLASSIFICATION

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

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

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the facility will be subject to Subpart KKKK, and may no longer be subject to subparts GG and Da. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a "Major Source" of HAPs and Unit 1 is not subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

SECTION I - GENERAL INFORMATION

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Southeast District, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix Da. NSPS Subpart Da Requirements for Duct Burners

Appendix GC. General Conditions

Appendix GG. NSPS Subpart GG Requirements for Gas Turbines

Appendix SC. Standard Conditions

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit; however, they are specifically related to this permitting action and are on file with the Department.

- Application received on April 14, 2005
- Department's Determination of Sufficiency – Found Insufficient June, 6 2005
- FMPA Sufficiency responses dated July 28, 2005
- Department's Second Determination of Sufficiency – Found Sufficient August 29, 2005
- Department's Intent to Issue and Public Notice Package dated October 28, 2005
- Letter from EPA Region IV dated __XXX_________
- Final Certification by the Power Plant Siting Board on XXXX; and
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

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

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

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. 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.]

5. 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. [Chapters 62-210 and 62-212, F.A.C.]

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

7. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Unit 1 Combined Cycle Gas Turbine (EU 001)

This section of the permit addresses the following emissions unit.

E.U. ID	Emission Unit Description
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards for Subpart Da, Subpart GG, and Subpart KKKK (as proposed). Some separate reporting and monitoring may be required by the individual subparts.

   (a) **Subpart A, General Provisions**, 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
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Subpart Da, Standards of Performance for Electric Utility Steam Generating Units** These provisions include standards for duct burners.

   (c) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (d) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions were published February 18, 2004 as a proposed new NSPS standard. The final rule will be applicable to Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

EQUIPMENT

3. Gas Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 170 MW. The gas turbine will be equipped with DLN combustors, and an inlet air filtration system with evaporative coolers. The unit shall include the Speedtronic™ Mark VI automated gas turbine control system, and will have dual-fuel capability. [Application; Design]

4. HRSG: The permittee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 565 MMBtu per hour (HHV).

The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. [Application; Design]

CONTROL TECHNOLOGY

5. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

6. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for the gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

7. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   Ammonia Storage: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

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

PERFORMANCE RESTRICTIONS

8. Permitted Capacity – Gas Turbine: The maximum heat input rate to the gas turbine is 1,787 MMBtu per hour when firing natural gas and 1,967 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

9. Permitted Capacity – HRSG Duct Burners: The total maximum heat input rate to the duct burners for the HRSG is 560 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

10. Hours of Operation: The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

11. Authorized Fuels: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. The

gas turbine shall fire no more than 500 hours of fuel oil, regardless of mode, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

12. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

   a. *Combined Cycle Operation*: The gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   b. *Pseudo Simple Cycle Operation*: The gas turbine/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

   c. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."

   d. *Duct Firing*: When firing natural gas, the HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

   [Application; Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

EMISSIONS STANDARDS

13. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, established in Condition No. 11 of this section, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be determined by the requirements in Condition No. 30 of this section. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, established in Condition No. 11 this section, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 30 of this section.

e. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

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

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

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

15. Definitions

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
    [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
    [Rule 62-210.200(230), F.A.C.]

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
    [Rule 62-210.200(159), F.A.C.]

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

17. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

18. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine/HRSG system, excess emissions from the gas turbine/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue}

b. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *Shutdown:* For shutdown of the combined cycle operation, excess emissions from the gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

d. *Fuel Switching:* Excess emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

19. Ammonia Injection: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbine/HRSG system including the pollution control equipment. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Determinations: The gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. The unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

23. Annual Compliance Tests: During each federal fiscal year (October 1st, to September 30th), the gas turbine shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NOX emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

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

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 18 and 20 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

RECORDS AND REPORTS

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

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

    c. *NSPS Semi-Annual Reports*: For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority. This also includes reporting any periods of excess emissions as applicable and defined by NSPS Subpart KKKK when the rule is finalized.

{Note: If there are no periods of excess emissions as defined in NSPS Subparts GG, Da, or KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

C. Fuel Oil Storage Tank (EU 002)

ID	Emission Unit Description
002	One distillate fuel oil storage tank for Unit 1 combustion turbine (approximately 1 million gallons).

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 5.2 kPa and greater than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the monitoring requirements. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. The fuel oil storage tank (EU 002) has a capacity greater than 151 cubic meters and the vapor pressure of the ultra low sulfur fuel oil is less than 3.5 kPa, therefore NSPS Kb, including the monitoring requirements, does not apply to this unit.
[40 CFR 60.110b(a) and (b), and 60.116b(c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one 990,000 gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 1 gas turbine. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year).
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for use in the Annual Operating Report.
[Rule 62-204.800(7)(b)16, F.A.C]

C. Cooling Tower (EU 003)

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

ID	Emission Unit Description
003	One 8-cell mechanical draft cooling tower.

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one 8-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 111,130 gpm; a design air flow rate of 1,000,000 acfm per cell; drift eliminators; a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 10 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}.

D. Safe Shutdown Generator (EU 004)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
004	One safe shutdown generator (approximately 765 hp).

NESHAPS Applicability

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

Equipment Specifications

1. Safe Shutdown Generator: The permittee is authorized to install, operate, and maintain one safe shutdown generator. The safe shutdown generator may operate when the transmission connection is lost and the plant shuts down, and during occasional testing to ensure operability. The safe shutdown generator will fire ULS fuel oil. [Application; Design]

Emissions and Performance Requirements

2. Hours of Operation: The safe shutdown generator may operate 200 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

{Permitting Note: Emissions from the safe shutdown generator are included in the potential to emit for the project.}

E. Diesel Fire Pump (EU 005)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
005	One diesel engine fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank.

NESHAPS Applicability

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

Equipment Specifications

1. Fire Pump: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank. The diesel engine fire pump will fire ULS fuel oil. [Application; Design]

Emissions and Performance Requirements

Hours of Operation: The fire pump may operate 200 hours per year.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.

{Permitting Note: The fire pump is considered emergency equipment, therefore exempt from permitting, however its emissions are included in the potential to emit for the project.}

SECTION IV. APPENDICES

CONTENTS

Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements for Duct Burners
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix SC	Standard Conditions

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur requirements. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using a HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:	Approved By:
Trina L. Vielhauer, Chief Bureau of Air Regulation	Michael G. Cooke, Director Division of Air Resources Management
Date	Date

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 1 gas turbine/HRSG system, which are regulated as Emissions Unit 001.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

"Duct burner" means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Gaseous fuel" means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

"Natural gas" means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835-87, 91, 97, or 03a (incorporated by reference, see 60.17).

"Gross output" means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.48a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart for a HRSG duct burner system firing solid, liquid, or other gaseous fuels.

In accordance with § 60.48a(k)(1), compliance with the nitrogen oxides (NO_X) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h)$ (Equation 1)

Where:

E = Emission rate of NOx from the duct burner, ng/J (lb/Mwh) gross output

Csg = Average hourly concentration of NO_X exiting the steam generating unit, ng/ dscm (lb/dscf)

Cte = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = Average hourly gross energy output from steam generating unit, J (Mwh)

h = Average hourly fraction of the total heat input to the steam generating unit de-rived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_X concentrations (Csg and Cte). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NOx limits established in the PSD permit shall demonstrate compliance with NO_X limit specified in NSPS Subpart Da.

In accordance with § 60.48a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.49a Emission Monitoring.

In accordance with § 60.49a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_X standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.50a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_X emission rate when demonstrating compliance with the NO_X standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.51a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

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 (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emssion Standards for Hazardous Air Pollutants (X); and
    d. 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 Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Unit 1 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

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

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(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.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_X) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

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

Where:

STD = Allowable NO_X 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 = NO_X emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(4) of this section.

§ 60.332(a)(3) defines an allowable NO_X contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9,355 Btu/KW-h at peak load and for oil firing is 10,120 Btu/KW-h at peak load. This results in "Y" values of 9.9 for gas firing and 10.7 for oil firing. The equivalent NSPS NO_X emission standards are 110/101 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NOx standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil (≤ 0.0015% sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_X standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_X) 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 H_2O/g air
e	=	Transcendental constant, 2.718
Ta	=	Ambient temperature, °K

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the specified NO_X limits. The permittee is allowed to make the initial compliance demonstration for NO_X emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_X monitor. The permittee is not required to have the NO_X monitor continuously correct NO_X emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

STANDARD CONDITIONS

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 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. <u>Records Retention</u>: 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. <u>Annual Operating Report</u>: 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

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 1110121-001-AC (PSD-FL-353, PA 05-48)

Treasure Coast Energy Center
St. Lucie County

Project type:

Project is construction of a nominal 300-megawatt (MW) combined cycle power plant with a 170 MW GE7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 130 MW steam turbine-electrical generator, a 170-foot stack, a mechanical draft cooling tower, a 990,000 gallon fuel oil tank and ancillary equipment. The unit will operate a maximum of 8,760 hours per year of which 500 hours per year may be on ultra low sulfur fuel oil (0.0015 percent sulfur).

The proposed continuous (24-hour) BACT NO_X limits are 2 ppmvd @15% O_2 when operating on natural gas and 8 ppmvd @15% O_2 when burning fuel oil. Other pollutants, including particulate matter (PM/PM_{10}), carbon monoxide, volatile organic compounds, sulfur dioxide, and sulfuric acid mist will be controlled by good combustion and use of clean fuels.

Projected impacts from the proposed project are all less than the applicable significant impact limits (SILs) corresponding to the nearby Class II areas and the Class I Chassahowitzka National Wildlife Area. The project will not cause or contribute to a violation of any National Ambient Air Quality Standard or Increment. The Fish and Wildlife Service had no adverse comments regarding this project.

The project is subject to Sections 403.501-518, F.S., Florida Power Plant Siting Act.

***I HEREBY CERTIFY** that the 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, and geological features).*

A A Linero 10/25/05

A A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
Permitting South Section
111 South Magnolia Drive, Suite 4 AAL 10/25
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

BEST AVAILABLE COPY

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

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A A Linero 10/25/05

A A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
Permitting South Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

A A L 10/25

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Roger A. Fontes, General Manager
and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Knowle Jones ☐ Agent ☐ Addressee

B. Received by (Printed Name) | C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
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3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 0320 0001 3692 1841

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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CERTIFIED MAIL RECEIPT
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Mr. Roger A. Fontes, General Manager
and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

PS Form 3800, January 2001 See Reverse for Instructions

Memorandum Florida Department of Environmental Protection

TO: Buck Oven, Power Plant Siting Office

FROM: Cindy Mulkey THROUGH Al Linero, Program Administrator

DATE: June 6, 2005

SUBJECT: FMPA Treasure Coast Energy Center
300 MW Combined Cycle Project

We have conducted our initial sufficiency review for the proposed FMPA Treasure Coast Energy Center project. Following are our sufficiency items:

General Electric (GE) advised in publication GER-4213 that they will provide a guarantee of 5 ppm for CO emissions on a case-by-case basis to avoid installation of oxidation catalyst. Such a guarantee was reportedly provided to FP&L for the recent Turkey Point Unit 5 project. Our own data from numerous new installations confirm low emissions on the order or 0.5 to 2.0 ppm. Please justify the higher values requested in light of GE's claims and the actual performance of the new GE 7FA units throughout the state.

In the BACT analysis included in the application, the use of selective catalytic reduction was considered cost effective for the control of NO_x at $3,546 per ton of NO_x removed. Please explain why oxidation catalyst to reduce CO emissions was not considered cost effective at $3,405 per ton of CO removed.

Please provide estimates of ammonia injection rates and projected ammonia use for the project.

In the application, section 4.2.5 states that receptors were placed along the "fence line." The receptor plot on 4-7 shows the "property line." Upon construction, will there be an actual fence separating the facility from the "ambient air" along the property line shown in 4-7?

In section 2.4 of the application, it is indicated that the Maximum Potential to Emit is based on 40 - 100 % load at 73 degrees. With an average annual site temperature of 73 degrees, the temperature is below 73 degrees about 50% of the time. Therefore, determining the Maximum Potential to Emit may be more representative of the area at 59 degrees. Please explain why determining the "maximum potential to emit" at 73 degrees would be more representative of the proposed project rather than at 59 degrees or re-evaluate the maximum potential to emit emission rates.

Rule 62-212.400(3)(h)(5) states that an application must include information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Although growth is addressed in section 5.1 of the application, please satisfy this rule by evaluating growth as it relates to the August 7, 1977 date.

In the application, Vegetation and Soils are addressed in Section 5.2. PSD pollutants, SO2, PM/PM10 and NOx are briefly mentioned. How will the other applicable PSD pollutants, SAM and CO, affect the vegetation and soils? How will all applicable PSD pollutants affect wildlife?

For the Class I analysis, CALPUFF was used. In Section 5.3.6 of the application, the meteorological data used in the model is detailed. 5 years of West Palm Beach NWS data were used for surface and upper air data for the entire modeling domain. According to comments the National Park Service made on 2/28/05 on the modeling protocol for this project, "appropriate NWS surface, upper air and precipitation stations from the modeling domain" is acceptable. The modeling domain extends much further than Palm Beach. Please include NWS station surface and upper air data that encompasses the entire modeling domain. Were hourly precipitation data used from NWS precipitation-recording stations within the modeling domain used? Was a horizontal grid spacing of 3km used as the National Park Service suggested in those same 2/28/05 comments?

In Section 2.4 of the application, it states that the PTE was based on 40-100% load at various temperatures for natural gas and fuel oil. Modeling for fuel oil at 40% load was not completed. Please complete this modeling if using fuel oil at 40% load is planned.

Please document consultation to-date with the EPA, the Federal Land Manager, and the U.S. Fish and Wildlife Service regarding any applicable provisions of the Endangered Species Act. We encourage your early contact with these agencies.

We did not receive any comments from the National Park Service or EPA Region 4. We will pass these on if and when received. Either agency might submit comments during the sufficiency review or during the normal comment period.

The DEP contacts for the PSD Permit application are Debbie Nelson (850/921-9537) for modeling issues and Cindy Mulkey (850/921-8968) on all other matters.

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AUG 01 2005

BUREAU OF AIR REGULATION

Florida Municipal Power Agency
Treasure Coast Energy Center

B&V Project 138859
B&V File 35.5500
July 28, 2005

Mr. Hamilton S. Oven, Administrator
Siting Coordination Office
Department of Environmental Protection
2600 Blair Stone Road
Suite 649, MS-48
Tallahassee, FL 32399-2400

Re: Florida Municipal Power Agency
Treasure Coast Energy Center
Site Certification Application No. PA 05-48
DOAH Case No. 05-1492EPP

Dear Mr. Oven:

On behalf of the Florida Municipal Power Agency (FMPA), and in response to the Notice of Insufficiency issued to Mr. Roger Fontes by the Florida Department of Environmental Protection on June 20, 2005, I am pleased to submit seventeen (17) copies of FMPA's detailed Sufficiency Response for your use and distribution. These 17 copies correspond to the Controlled Document copies (Copies 1-10, 28-31, and 51-53) of the Site Certification Application assigned to you. Please be assured that a copy of this Sufficiency Response will also be provided to those on the following Certificate of Service List which are Controlled Document holders of the SCA.

We appreciate the Department's cooperation and efforts as this application progresses through the review and certification process. If you have any questions concerning the project or this Sufficiency Response, please do not hesitate to call Jim Hay of FMPA at (407) 355-7767 or me at (913) 458-7563.

Very truly yours,

Mike Soltys

J. Michael Soltys
Site Certification Coordinator

Enclosures

cc: Jim Hay, FMPA
Certificate of Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Sufficiency Response has been forwarded by Federal Express or U.S. mail delivery to the following listed persons this 28TH day of July, 2005:

Tim Gray
Dept. of Environmental Protection

Al Linero
Dept. of Environmental Protection

Jim Golden
South Florida Water Management District

Paul Darst
Dept. of Community Affairs

James Antista
Fish & Wildlife Conservation Commission

Scott Sanders
Fish & Wildlife Conservation Commission

Steve Lau
Fish & Wildlife Conservation Commission

Forrest Watson
Dept. of Agriculture and Consumer Services

Roger Orr
City of Port St. Lucie

Faye Outlaw
St. Lucie County

Judy Harlow
Public Service Commission

Leslie Bryson
Public Service Commission

Sheauching Yu
Dept. of Transportation

Sandra Whitmire
Dept. of Transportation

Forrest Watson
Dept. of Agriculture

Barton Bibler
Dept. of Environmental Protection

Janet Snyder-Matthews
Dept. of State

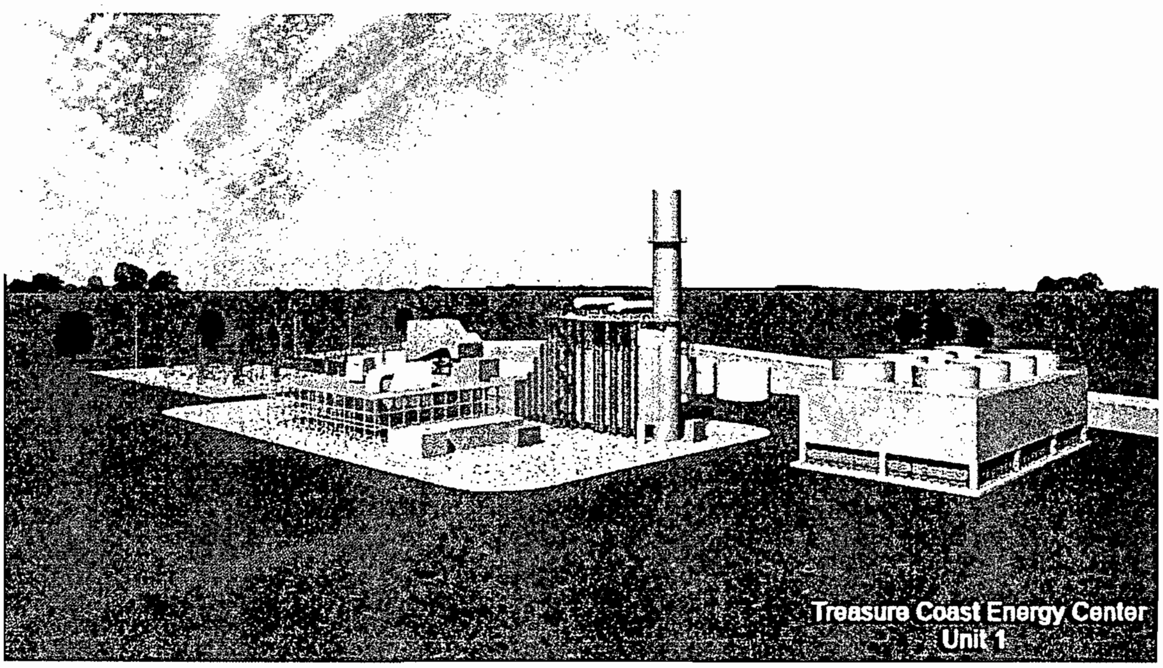
Peter Merritt
Treasure Coast Regional Planning Council

Dan McIntyre
St. Lucie County

Florida Electrical Power Plant Siting Act
Site Certification Application

Sufficiency Responses

Treasure Coast Energy Center



Submitted by:
Florida Municipal Power Agency
July 2005

Florida Municipal Power Agency
Community Power. Statewide Strength.

Treasure Coast
ENERGY CENTER

Treasure Coast Energy Center

Site Certification Application Sufficiency Responses

Engineering Certification Statement

I, the undersigned, hereby certify that:

The engineering features of Treasure Coast Energy Center Project – Unit 1 described in these sufficiency responses have been prepared, designed, or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles; and,

To the best of my knowledge, the information submitted in support of the sufficiency responses is true, accurate, and complete based on reasonable techniques, estimates, materials, and information gathered and evaluated by qualified personnel; and,

To the best of my knowledge, there is reasonable assurance that the Unit 1 project described in these responses, when properly operated and maintained, will comply with all applicable pollution control standards found in the Florida Statutes, and rules of the Department of Environmental Protection, and the South Florida Water Management District, which have been adopted by St. Lucie County for stormwater management.

Name: Stanley A. Armbruster Date: July 29, 2005
Florida License No. 30562
Black & Veatch
11401 Lamar
Overland Park, Kansas

STANLEY A. ARMBRUSTER
LICENSE
30562
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

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Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

June 17, 2005

Mr. Roger Fontes, General Manager
Florida Municipal Power Agency
8553 Commodity circle
Orlando, Florida 32819-9002

Re: Treasure Coast Energy Center, PA 05-48,
DOAH Case No 05-1492EPP; OGC Case No. 05-0744

Dear Mr. Fontes:

Pursuant to § 403.5067, Florida Statutes, the Department of Environmental Protection after consulting with the affected agencies has determined that the application for site certification lacks sufficient information to support a recommendation of certification.

Figure 2.3.5 FLUCCS Land Use is missing. Section 6.1.10 does not contain the information necessary to determine compliance with local noise regulations nor compliance with Chapter 62-814, F.A.C. concerning electric and magnetic fields.

The Bureau of Air Regulation has conducted an initial sufficiency review for the proposed FMPA Treasure Coast Energy Center project. Following are their sufficiency items:

1. General Electric (GE) advised in publication GER-4213 that they will provide a guarantee of 5 ppm for CO emissions on a case-by-case basis to avoid installation of oxidation catalyst. Such a guarantee was reportedly provided to FP&L for the recent Turkey Point Unit 5 project. Our own data from numerous new installations confirm low emissions on the order or 0.5 to 2.0 ppm. Please justify the higher values requested in light of GE's claims and the actual performance of the new GE 7FA units throughout the state.

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3. Please provide estimates of ammonia injection rates and projected ammonia use for the project.

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8. In the application, Vegetation and Soils are addressed in Section 5.2. PSD pollutants, SO2, PM/PM10 and NOx are briefly mentioned. How will the other applicable PSD pollutants, SAM and CO, affect the vegetation and soils? How will all applicable PSD pollutants affect wildlife?

The Southeast district Office had the following comments:

1. What environmental assessments have been conducted or will be conducted in order to determine whether soil, sediments, groundwater, or surface waters have been adversely affected (contaminated) by the agricultural operations? Some agricultural operations have had a historical usage of, among other things, arsenical-based pesticides and herbicides. Part of the environmental assessment must include, among other things, the details of historical and current pesticide usage, identification, including detailed, scaled maps, of current and historical fertilizer and pesticide / herbicide mixing areas, locations of canals and surface water bodies, locations of any above-ground, underground or temporary storage tanks, farming equipment maintenance and storage, petroleum product storage, on-site landfill / solid waste disposal areas, locations and types of any water production wells (potable, pesticide make-up, irrigation, etc.), locations and types of surface water pumps and associated fuel tanks, etc. What soil, sediment, surface water and groundwater cleanup concentrations would be proposed? Are there monitoring wells available for sampling of groundwater? If so, does the facility sample and monitor groundwater from these wells? Please provide a list of the monitored parameters and the results from the sampling and enclose a map depicting these groundwater monitoring wells.

2. Page 2-9 states that the existing site is pasture land. Historical cattle ranching operations may have had cattle dip vats to control diseases. An environmental investigation should be initiated in order to determine the current or historical presence of cattle dip vats at the site associated with ranching operations. Such vats, when identified, would require assessment and probable cleanup.

3. What reasonable assurances can be provided to show that on site water production wells and dewatering will not affect any off-property soil / groundwater contaminated areas? Page 4-8 lists some potential impact from "low scoring" petroleum facilities. Detailed information needs to be provided, including a map(s), showing these contaminated areas and any potential affects new withdrawals, storm water discharges, dewatering, etc. could affect. The St. Lucie County Glades Road Landfill is currently undergoing contamination assessment and that facility has a permitted zone of discharge in their Solid Waste Permit, issued pursuant to, among others, Chapters 62-701, 62-520 and 62-522, Florida Administrative Code (F.A.C.). Page 4-9 does not mention this facility.

4. Section 3-.7, pgs 3-28, 3-29, and 3-30.
Please be advised that hazardous waste determinations are required for most wastewaters generated (including "washdowns") in accordance with Title 40 Code of Federal Regulations (C.F.R.) Part 261, as referenced in Chapter 62-730, F.A.C. In addition to any industrial waste treatment and monitoring requirements, all waste streams must be characterized for proper hazardous waste management in accordance with 40 C.F.R. Part 261, including wastes collected in sumps, laboratory wastes and material from solids settling basins . Page 4-4 has a chart and description of waste streams. The chart and a description needs to be included that indicates which waste stream would be hazardous, whether it is based on process knowledge or will be based on analytical testing, and if hazardous, additional information regarding how the facility would manage the storage and treatment of such wastes in accordance with Chapter 62-730, F.A.C., which references portions of Title 40 C.F.R. Parts 260-271, would be required.

5. Any land clearing or construction debris must be characterized for proper disposal. Potentially hazardous materials must be properly managed in accordance with Chapter 62-730, F.A.C. In addition, any solid wastes or other non-hazardous debris must be managed in accordance with Chapter 62-701, F.A.C.

6. Petroleum and hazardous materials storage tanks and emergency generators for planned facilities must be constructed to comply with the current requirements of Chapter 62-761 and / or 62-762, F.A.C. An acknowledgment that these facilities would comply with the applicable requirements of these rules should be included. As an example, secondary containment should be planned for all areas where petroleum or hazardous materials discharges could affect soils, sediments, surface or ground waters.

7. The applicant states that they will be using water from the Floridan Aquifer. The applicant has applied for 6 wells at a depth of @ 500 feet. The operation of these wells will cause a draw down of the water table several thousand feet away. Within 1800 feet of this proposed site is the existing St. Lucie County Glades Road Landfill. The landfill is under a Consent Order performing CAP/CAR/RAP for offsite contamination at the east and northeast portion of the landfill property boundary in the shallow aquifer (@ 20 to 40 feet in depth) from the old unlined class I landfill located at the intersection of I-95 and the Fla. Turnpike. The groundwater flows northeast in this area. The applicant also proposes to do dewatering via a GP to the SFWMD. The applicant needs to demonstrate that the proposed dewatering

and proposed production wells will not affect the landfill plume or draw the landfill plume to the applicant's or other adjacent properties. The applicant should also demonstrate that the shallow production zone and Floridan aquifer are not connected.

The Bureau of Water Facilities has the following comments:

1. Sections 373.250 and 403.064, F.S., establish the encouragement and promotion of water reuse as state objectives and note that reuse is in the public interest. Further, Chapter 62-40, F.A.C., requires use of reclaimed water within designated Water Resource Caution Areas. This proposed plant is located within a Water Resource Caution Area. The Department applauds the use of reclaimed water for cooling water at this facility. Part VII of Chapter 62-610, F.A.C., specifically addresses and allows for the use of reclaimed water in cooling water applications. This use of reclaimed water is consistent with statutory and rule directives and objectives. Has wastewater from the City of Port St. Lucie been considered as a source until the Fort Pierce supply is available?

2. Has reclaimed water been considered for use in the fire protection system or for toilet flushing purposes? Please note that Part III of Chapter 62-610, F.A.C., allows the use of reclaimed water for toilet flushing, fire protection, and other uses. Both of these are excellent uses of reclaimed water and should be incorporated into the project, if feasible.

3. In accordance with Rules 62-610.660 and 62-555.360, F.A.C., the SCA should evaluate the need for backflow prevention devices on reclaimed water and potable water lines to prevent either source from being contaminated.

4. The first generating unit at the power plant (Unit 1) is scheduled to begin commercial operation in June 2008, pending certification and construction. According to the SCA, the POTW is expected to be operational by "late 2009." The SCA text and the water mass balances indicate that the injection wells are the only means of disposal for wastewater from the power plant, so the wells have to be permitted, constructed, and in operation for the power plant to operate. There did not appear to be a schedule for the injection wells at the POTW. The applicant needs to clarify this point and provide demonstrate that the power plant will have a means for disposal of cooling tower blowdown, other process wastewaters, and domestic wastewater.

5. How will power plant operations be impacted if the POTW cannot provide sufficient reclaimed water long-term due to slower than expected population growth or other factors?

6. How will power plant operations be impacted when injection wells at the POTW are out of operation for mechanical integrity testing or other maintenance activities? Will they have multiple wells?

7. Section 3.6.2 implies that a force main to the unbuilt FPUA plant already exists. Is this correct?

8. Figure 3.5-6 shows 942,000 gpd as the annual average of wastewater going to the injection well, not the 889,000 gpd reported in the text. Please clarify.

The South Florida Water Management District had the following comments:

South Florida Water Management District (SFWMD) staff has reviewed the Site Certification Application (SCA) submitted by the Florida Municipal Power Agency (FMPA) for the above subject project, as required by Sections 403.501-518, F.S., and Rule 62-17, F.A.C. As a result of that review, we have identified the following outstanding issues/sufficiency questions which must be addressed in order for the SFWMD to complete its review of this project. Please include the following questions/comments in your sufficiency letter on this project.

(1) Please specify the water supply quantity/source for dust control.

(2) Please submit the details of the proposed wells as required in Table A (Form 0645-G-60).

(3) The calculations provided in response to Section F.1 of the Water Use Permit Application Form indicate that the values are based on using groundwater for cooling for Unit 1. Section G.1 of the Supporting Information states that, excluding the cooling system, 597,000 gallons per day of water are required for Unit 1. Please provide a breakdown of all of the water use demand using the appropriate tables, including Table D (Form 0645-G65), Table G (Form 0645-G69), and Table I (Form 0645-G-71).

(4) The groundwater modeling must follow the criteria set forth in Section 1.7.5.2 of the Basis of Review (BOR) for Water Use Permit Applications. Please note that the extrapolation of site-specific characteristics from a calibrated model is not in accordance with SFWMD criteria. Please submit revised modeling that meets the requirements set-forth in Section 1.7.5.2 of the BOR.

(5) Please submit a letter from the Fort Pierce Utilities Authority (FPUA) documenting the availability of reclaimed water for the proposed project, as required by Section G.1.4 of the Water Use Permit Application Form.

(6) Please supply a letter from the FPUA documenting the availability of potable water for the proposed project, pursuant to the discussion on page 6 of the Additional Information in Support of TCEC Industrial Water Use Request.

(7) The SCA indicates that the details of the proposed dewatering activities will be submitted during the post-certification review process. Please be advised of the following:

(a) Section D.4 of the Dewatering Permit Application and Section 4.4.1 of the Site Certification Application state that wetlands will remain on-site. In addition, wetland areas are present within the surrounding project area. As per

Section D.5 of the Dewatering Permit Application, modeling or specific engineering controls that include recharge trenches may be necessary to provide reasonable assurances that no harm occurs to wetland areas due to the proposed withdrawals or discharges.

(b) A known contaminated facility is located approximately 400 feet east of the project site (Florida Department of Environmental Protection Facility ID No. 8631089). As per Section E.1 of the Dewatering Permit Application, modeling may be necessary to provide reasonable assurances that there are no adverse impacts due to the proposed withdrawals or discharges.

(c) The licensee must submit calculations showing that the detention basin has sufficient capacity to accept dewatering effluent.

If you have any questions concerning these matters, please contact me at (850) 245-8002.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

Attach:
cc: Scott Goorland, Esq.
Douglas S. Roberts, Esq.
James V. Antista, Esq.
Kelly Martinson, Esq.
Sheauching Yu, Esq.
Martha Carter Brown, Esq.
Dan McIntyre, Esq.
Frank H. Fee, III, Esq.
Roger Orr, Esq.
Roger Saberson, Esq.
Peter Cocotos, Esq.

Response to Statement of Insufficiency
Treasure Coast Energy Center
July 29, 2005

Comment FDEP/Siting-1

Figure 2.3.5 FLUCCS Land Use is missing.

Response FDEP/Siting-1

Due to a copying error, Figure 2.3-5 was not included in some copies of the SCA. One copy of Figure 2.3-5 is provided with this response in Appendix A. Please insert this figure into your copy of Volume 1 of the SCA following page 2-57 (Figure 2.3-4). Additional copies of this figure are available upon request to FMPA.

Comment FDEP/Siting-2

Section 6.1.10 does not contain the information necessary to determine compliance with local noise regulations nor compliance with Chapter 62-814, F.A.C. concerning electric and magnetic fields.

Response FDEP/Siting-2

There are no regulatory requirements specific to transmission line noise emissions included in Chapter 1-13.8, Noise Control, of the St. Lucie County Code of Ordinances. Transmission line noise emissions typically include crackling and/or humming noises associated with electrical transmission and can vary depending on factors such as electrical capacity and load of the line, temperature, and moisture levels in the air. Although it is possible for transmission line noise to be audible at certain times and under certain conditions, this type of noise typically can only be heard very near the transmission line (i.e., within the transmission line right-of-way). The proposed corridors for the transmission lines were selected to minimize environmental impacts and make the most direct interconnections. These linear facilities are proposed within or adjacent to existing road, railroad, or utility rights-of-way, crossing commercial, industrial, utility, and transportation land uses, avoiding residential and sensitive properties by design. Therefore, considering the cumulative noise sources and impacts currently in the site area, such as heavy truck traffic, industrial activities, and landfill operations, no adverse or nuisance impacts due to project transmission line acoustic noise are expected. It is also anticipated that any audible transmission line noise would be below the St. Lucie County noise limits for residential, commercial, and industrial areas.

Florida Department of Environmental Protection (Department) EMF compliance reports for TL1 and TL2 were prepared using the required EzEMF program and are included in Appendix B. The calculations are conservatively based on 2,000 amps per phase. The transmission lines will be in compliance with the FDEP electric and magnetic field strength limits.

When an electric transmission line is energized, an electric field is generated in the air around the conductors. This electric field may cause corona. Corona is the breakdown of the air in the vicinity of the transmission line phase conductors. This corona discharge produces energy, which can result in audible noise and/or radio and television interference. However, corona related interference with radio and television reception is typically associated with transmission line voltages of 345 kV or greater. If corona related interference does occur, it can easily be identified and corrected with proper maintenance.

The Florida Public Service Commission has adopted the 2002 edition of the National Electrical Safety Code (NESC). Specifically, the code requires minimum electrical clearance to the ground and the structure, and limits induced currents in objects below the line to 5 mA. In addition, the code specifies minimum mechanical loading to be used for the structural design of the support structures. The transmission facilities will be designed to comply with all safety requirements contained in the NESC.

Comment FDEP/BAR-1

General Electric (GE) advised in publication GER-4213 that they will provide a guarantee of 5 ppm for CO emissions on a case-by-case basis to avoid installation of oxidation catalyst. Such a guarantee was reportedly provided to FP&L for the recent Turkey Point Unit 5 project. Our own data from numerous new installations confirm low emissions on the order or 0.5 to 2.0 ppm. Please justify the higher values requested in light of GE's claims and the actual performance of the new GE 7FA units throughout the state.

Response to FDEP/BAR-1

GE is able to provide FMPA with a lower guarantee level for CO under defined ambient air and load conditions, as shown in Table FDEP-1 (included in Appendix C) listing the GE guarantees for the TCEC Project. However, the lower guarantee levels do not apply to ambient air and load conditions that encompass all expected operating conditions for TCEC Unit 1. As such, to enable the permitted CO emission standards to encompass the full range of expected operating conditions of TCEC Unit 1, FMPA requests that the CO standards for TCEC Unit 1 be set at 8.0 ppmvd for natural gas firing and 12.0 ppmvd for fuel oil firing, based on a 24 hour block average (midnight to midnight). These requested emission limits are identical to the Department's BACT-determined CO standards for the Progress Energy Florida Hines Energy Complex Power Block 4, as included in that recently issued PSD permit (Permit No. PSD-FL-342). This emission limit will allow for BACT level control and will encompass all operating conditions expected for TCEC Unit 1. The Hines Energy Complex Power Block 4 Units are General Electric Model 7FA gas turbines, as is the TCEC Unit 1 combustion turbine. The Hines Energy Complex combustion turbines include heat recovery steam generators (HRSG) with no duct firing. However, TCEC Unit 1 includes a HRSG with duct firing. The use of duct firing results in a higher expected CO concentration in the CT/HRSG stack. Therefore, the Hines Energy Complex Power Block 4 units would be expected to have lower CO emissions than TCEC Unit 1. As such, these emission standards applied to TCEC Unit 1 represent a more stringent emission limit because TCEC Unit 1 includes operation with duct firing. It is also noted that the application for TCEC Unit 1 includes a voluntary limit on fuel oil firing of 500 hours per year, as compared to a fuel oil firing limit of 1,000 hours per year per turbine for both of the two combustion turbines included in the Hines Energy Complex Power Block 4 permit. This allows Hines Energy Complex Power Block 4 more operating time at the higher fuel oil firing CO limit than what is requested for TCEC Unit 1.

As noted in the final determination for Hines Energy Complex Power Block 4, the FPL Turkey Point plant is located approximately 20 km from a Class I area (Everglades National Park), providing the Department with a different set of "lenses," or criteria, by which to establish emission limits. Like the Hines Energy Complex, the TCEC facility is not located in close proximity to a Class I area, as Turkey Point is, which provides justification for the requested CO emission limits given above. Also of note is that the TCEC facility is located outside the Miami-Dade, Broward, and Palm Beach airshed that includes Turkey Point. As mentioned by the Department in the Hines Energy Complex Power Block 4 Final Determination document, the CO limit given to Hines Energy Complex Power Block 4 and hereby requested for TCEC Unit 1 is identical to that of Turkey Point, without the requirement for an annual test.

Comment FDEP/BAR-2

In the BACT analysis included in the application, the use of selective catalytic reduction was considered cost effective for the control of NO_x at \$3,546 per ton of NO_x removed. Please explain why oxidation catalyst to reduce CO emissions was not considered cost effective at \$3,405 per ton of CO removed.

Response to FDEP/BAR-2

Individual BACT determinations are performed on a case-by-case basis for each pollutant subject to PSD review. As a basis for review, permitting authorities have historically and routinely established cost-effective guidelines, either internally or overtly, that are pollutant-specific, considering the control technology, environmental sensitivity, and determinations from similar BACT trends for that pollutant in the affected region and across the country. FMPA is not aware of an "inter-pollutant" comparison criterion in the BACT process, and believes the recommended "top-down" BACT approach is pollutant-specific and independent of other pollutant determinations in the analysis, except of course in those instances where multi-pollutant control technologies are examined ($SCONO_x$, for example).

FMPA is aware of other recent Department BACT determinations where similar trends in the relationship between the CO and NO_x control cost effectiveness are evident. In the Department's FPL Martin Combined Cycle Unit 8's final BACT determination, for example, the Department states that FPL's proposed cost effectiveness of \$4,165/ton for an oxidation catalyst was not found to be cost effective for CO control, while an SCR, with a cost effectiveness of \$4,900/ton, was found to be cost effective for NO_x control. It would appear that an inter-pollutant cost effectiveness comparison was not considered in the BACT determination for either pollutant, as the oxidation catalyst (by the applicant's account) was more than \$700/ton more cost effective than the SCR for NO_x control.

FMPA believes that an oxidation catalyst is not BACT for this project. This determination is independent of the NO_x control determination. FMPA would not have found an oxidation catalyst to be cost effective, having gone through the same five-step BACT technology selection approach regardless of whether NO_x would have been subject to a BACT review or not. The CO BACT assessment is firmly based on the energy, environmental, and economic impacts detailed in the application, as well as recent Department determinations for similar units at similar emission levels. In those determinations, the Department has found that add-on controls to further reduce CO emissions are unwarranted given the low emissions characteristics of this particular gas turbine firing natural gas as the primary fuel.

Comment FDEP/BAR-3

Please provide estimates of ammonia injection rates and projected ammonia use for the project.

Response to FDEP/BAR-3

The estimated ammonia injection rate based upon 100 percent ammonia is 44.58 lb/h. The projected ammonia use for the project based upon permitted dual fuel firing 8,760 hours at maximum load with duct burners operating is approximately 195 tons per year. The TCEC will store 19 percent aqueous ammonia for the SCR, which is vaporized to a gaseous (100 percent) form prior to injection into the exhaust gas stream.

Comment FDEP/BAR-4

In the application, Section 4.2.5 states that receptors were placed along the "fence line." The receptor plot on 4-7 shows the "property line." Upon construction, will there be an actual fence separating the facility from the "ambient air" along the property line shown in 4-7?

Response to FDEP/BAR-4

Yes, a fence separating the facility from the ambient air will be constructed. Figure 4-1 on page 4-7 in SCA Volume 3 of 3 should have been labeled "fence line," not "property line." The distinction between the actual property line and fence line is illustrated on Drawing 138859-CSTA-S1002, Ultimate Site Arrangement, included in Appendix D. The fence line, not the property line, was used in designating ambient air for the air quality impact analysis. This new site arrangement includes a slight change to the facility fence line.

In addition to the fence line clarification, other changes noted on the new Site Arrangement include the following:

- Removed the auxiliary boiler and associated building (35).
- Added surfacing boundaries. Grass north of the cooling towers.
- Added asphalt paved sidewalks through the unit and to the gas metering station.
- Moved Electrical Equipment Building (41) to the south side of the steam turbine.
- Added the Miscellaneous Services Building (42) to the north side of the steam turbine. Each building will service two units.
- Moved the Fire Pump Building (28) to allow for better access. This required rearrangement of the water treatment tanks.
- Changed the location of the Water Treatment Building (24) and the Administration/Control/Maintenance Building (18).
- Added parking spaces to meet county code.

- Added entrance sign (50) to the northeast entrance.
- Changed the southwest entrance to future.
- Added the Switchyard Control Building (52).
- Added condensate storage tank (49).
- Added electrical interface manhole (53) and piping interface manhole (54).
- Removed the Chemical Feed Building (38).

Some of the facility changes may affect the impacts from the air dispersion models, ISCST3 and CALPUFF. With respect to air quality modeling, the changes of concern are as follows:

- Removed the auxiliary boiler and associated building (35).
- Moved Electrical Equipment Building (41) to the south side of the steam turbine.
- Added the Miscellaneous Services Building (42) to the north side of the steam turbine.
- Moved the Fire Pump Building (28) to allow for better access. This required rearrangement of the water treatment tanks.
- Changed the location of the Water Treatment Building (24) and the Administration/Control/Maintenance Building (18).
- Changed the southwest entrance to future.
- Added the Switchyard Control Building (52).
- Added condensate storage tank (49).
- Removed the Chemical Feed Building (38).

The applicable modeling was rerun with the above referenced changes made to both Class I (CALPUFF) and Class II (ISCST3) modeling analyses. There were no other changes made to the modeling. The new impacts are shown in the tables included in Appendix E (Tables 4-2, 4-3, 5-5, 5-6, and 5-7, numbered as in Volume 3 of 3 in the original SCA). As can be seen from these tables, the changes made to the facility layout did not change the impacts from the combustion turbine alone, and the overall facility air quality impacts are lower than the results with the initial site arrangement that was included in the SCA.

As discussed above and demonstrated by the revised modeling, these changes did not adversely affect the air quality impact analysis for the project. Also, these changes had no significant effect on the storm water management system design, wetlands impacts, or other project-related impacts.

Comment FDEP/BAR-5

In Section 2.4 of the application, it is indicated that the Maximum Potential to Emit is based on 40 - 100% load at 73 degrees. With an average annual site temperature of 73 degrees, the temperature is below 73 degrees about 50% of the time. Therefore, determining the Maximum Potential to Emit may be more representative of the area at 59 degrees.

Response to FDEP/BAR-5

FMPA agrees that, about 50 percent of the time, the ambient temperature will be below 73° F. Conversely, about 50 percent of the time, the ambient temperature will be above 73° F. The combustion turbine performance data shows that the emissions rate is relatively linear as a function of ambient temperature for each pollutant. Therefore, over the course of a year, increased emissions associated with operation at a temperature that is lower than the site average ambient temperature are directly countered by decreased emissions associated with operation above the site average ambient temperature.

Comment FDEP/BAR-6

Please explain why determining the "maximum potential to emit" at 73 degrees would be more representative of the proposed project rather than at 59 degrees or re-evaluate the maximum potential to emit emission rates.

Response to FDEP/BAR-6

FMPA believes that the best method to estimate the potential to emit for the TCEC project is to use the hourly emission rates at the site's average ambient temperature and project operation for 8,760 hours per year, as was included in the SCA. Further, the potential to emit calculation is quite conservative in that it assumes that TCEC Unit 1 will operate at full load for an entire year.

The primary use of the calculated potential to emit is to make comparisons to regulatory thresholds to determine rule applicability. The primary regulatory thresholds for the TCEC Unit 1 application are those used to determine PSD applicability. While FMPA believes that the use of emissions data at the site average ambient temperature provides the best method of determining the potential to emit for the project, the potential to emit calculations using a 59° F ambient temperature for comparison purposes, along with the potential to emit values included in the SCA (associated with an ambient temperature of 73° F), is shown in Table FDEP-2 in Appendix F. Table FDEP-2 shows that using an ambient temperature of 59° F to determine the potential to emit results in minimal, but increased emission changes when compared to the potential to emit included in the application. Also, this table shows that no PSD regulatory applicability determinations would be affected by the use of an ambient temperature of 59° F to determine the potential to emit. Note that to properly determine the project potential to emit, the emissions from TCEC Unit 1 are added to the potential to emit emission levels of other project emission units and the values in the table are the project potential to emit. The differences in the potential to emit for the two site ambient temperatures shown are equivalent to the difference in the potential to emit for TCEC Unit 1, because emissions from all other emission units are unaffected by the ambient temperature.

Comment FDEP/BAR-7

Rule 62-212.400(3)(h)(5) states that an application must include information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Although growth is addressed in Section 5.1 of the application, please satisfy this rule by evaluating growth as it relates to the August 7, 1977 date.

Response to FDEP/BAR-7

FMPA assumes that the question refers to Rule 62-212.400(**5**)(h)(5), not 62-212.400(**3**)(h)(5), F.A.C. As such, the nature and extent of air quality impacts related to all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, can be characterized by the population trend of the area as a surrogate for general growth. An evaluation of the growth as it relates to the August 7, 1977 date, as well as a projection of growth indicators related to the TCEC with respect to workforce, housing, and commercial/industrial growth and their potential impact to air quality are presented below.

<u>Growth Analysis</u>

The TCEC is located within Phase III North of the Midway Industrial Park in St. Lucie County, Florida, which is southwest of the City of Ft. Pierce, and 5 miles northwest of Port St. Lucie. The proposed TCEC site occupies 68.1 acres in Section 31, Township 35 South, Range 40 East, and is currently a greenfield site used for cattle pasture that was approved for industrial use in January 1993 by the St. Lucie County Board of Commissioners for development as an industrial park. The site is zoned Utility.

St. Lucie County is currently the third fastest growing county in Florida, with much of the growth occurring in the cities of Ft. Pierce and Port St. Lucie. The county and its two major cities provide the amenities of larger metropolitan centers in areas such as health care, education, employment opportunities, and recreation; yet the current county population of only 214,100 (2005 projected) allows these areas to retain a spirit of community and a small town atmosphere.

The population trends of St. Lucie County may be used as a surrogate growth indicator of the extent of air quality impacts related to general commercial, residential, and industrial growth since August 7, 1977. The U.S. Census Bureau estimated that St. Lucie County had a population of 74,189 persons in 1977. The population of St. Lucie County was estimated to be 213,447 persons in 2003 by the U.S. Census Bureau, and this constituted 1.25 percent of the estimated state population of 17,019,068. The St. Lucie County population increased by 10.8 percent between 2000 and 2003, compared to a 6.5 percent growth for Florida. The respective 1990 to 2000 growth rate was 28.3 percent for St. Lucie County compared to 23.5 percent for Florida. The St. Lucie County population is expected to increase to 214,100 in 2005, constituting a population increase of 188.6 percent since 1977.

Since 1977, St. Lucie County has successfully balanced growth and economic development with the preservation of unique environmental and recreational areas. The County has anticipated and planned for this additional growth while continuing to demonstrate compliance with the air quality standards (St. Lucie County is in attainment for all criteria pollutants) and preserving the amenities offered to the county population and its visitors. Because the maximum predicted air pollutant concentrations for the TCEC project are well below the NSR/PSD significant impact and increment levels, air concentrations in the region are expected to fully comply with the ambient air quality standards when TCEC becomes operational. Therefore, from an air quality impact standpoint, the proposed TCEC facility is consistent with the balanced growth demonstrated by the county to date.

Workforce

Employment figures for the Ft. Pierce-Port St. Lucie Metropolitan Statistical Area (MSA) for November 2003 show 111,190 persons employed. The largest occupational category was the office and administrative support area (20,920 or 18.8 percent). This category was followed by sales and related occupations (14,050 or 12.6 percent), and food preparation and serving occupations (10,560 or 9.5 percent). Major employment sectors in the county included the education services sector (9.2 percent), the health care and social services sector (13.3 percent), and 28.1 percent were in the "other services" classification. Construction and real estate (9.2 percent) and professional and business services (8.5 percent) also made up a significant portion of the St. Lucie County employment by industry.

Compared to the rest of the state, St. Lucie County had a relatively higher concentration of employment in the agriculture, natural resources, and mining sector (6.0 percent versus 1.5 percent), the education sector (9.2 percent versus 7.2 percent), and the government sector (8.3 percent versus 6.1 percent). The county was well below the state percentage in the professional and business services sector (8.5 percent versus 17.0 percent, respectively).

County business data for St. Lucie County for 1977 show the mid-March total employment to be 14,911 persons. The largest occupational category was in the retail trade division (4,585, or 30.7 percent). This category was followed by the service division (3,345, or 22.4 percent) and the manufacturing division (1,958, or 13.1 percent). Other major employment divisions in the county included wholesale trade (8.9 percent), construction (7.8 percent), finance, insurance, real estate (5.9 percent), and transportation, communications, and utilities (5.4 percent). Non-classifiable establishments and the mining division make up the remainder of the occupational categories.

Workforce Growth Associated with the Project

The TCEC project will require a substantial construction workforce during the 22 month construction period, scheduled to span the August 2006 to May 2008 time frame. During this period, an average of 119 direct craft construction workers and a total workforce (that also includes indirect craft workers, construction management, and local utility staff) average of 169 personnel are expected. The peak construction workforce is projected to occur during the eleventh month of construction, when 233 direct craft workers, and a total of 286 workers, are expected onsite. However, the construction labor force increase and associated secondary air emissions increase will be temporary and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the TCEC.

The net number of new, permanent jobs that will be created by TCEC Unit 1 is estimated at 16. The secondary residential, commercial, and industrial growth associated with this small operation staff, which will be divided into shifts to provide around-the-clock operation, is not expected to have a significant impact on air quality.

Housing

According to the U.S. Census Bureau, there were 96,123 housing units in St. Lucie County in 2002. This was 1.3 percent of the 7,624,378 units in the state. The number of housing units in 2002 compared to a figure of 91,262 reported in the 2000 US Census, which also reported 17,170 housing units in Ft. Pierce, and 36,785 housing units in Port St. Lucie. Home ownership rate in the county was high at 78 percent versus a 70 percent ownership rate for Florida. In 1980, there were 40,915 housing units in St. Lucie County, constituting an increase in housing units of 135 percent between 1980 and 2002. The home ownership rate in St. Lucie County in 1980 was 54 percent.

The housing stock in St. Lucie County is relatively young, reflecting the recent population growth. Approximately 64 percent of the housing stock in 2000 was built in 1980 or later, and only 7.6 percent of the housing stock was built before 1960. Approximately 50 percent of the 2000 population moved into their housing unit in 1995 or later, and approximately 70 percent in 1990 or later.

Building activity for St. Lucie County has continued at a rapid pace during the recent past, as reflected in the number of housing unit building permits issued. In 2003, a total of 7,684 permits were issued for the county, and this was equal to nearly 8 percent of the 2002 existing housing stock. During the past 5 years, the type of housing unit for which a building permit was issued has been primarily for single family structures, though multi-family structures also comprised a significant percentage in 2002 (38 percent) and in other years.

Housing Growth Associated with the Project

The potential for housing shortages and thus the possibility of housing related growth and secondary air quality impacts have been an issue historically for the construction of large coal plants in sparsely populated areas. However, experience has also shown that smaller projects (non-coal plants) like the TCEC located in or near urban areas typically have no noticeable impacts on the housing market. The reason is that impacts are primarily a function of the size of the construction workforce and the need for the workforce to relocate during construction.

The need to relocate is a function of the available workforce within a reasonable commuting distance of the work site. Research by the Electric Power Research Institute (EPRI) has indicated that the construction workforce for a power plant project can reasonably be expected to commute without relocating during construction from a distance of more than 70 miles, with instances of a commuting distance of more than 100 miles found in each of the construction projects studied. When a 70 mile radius around the TCEC site is considered, large metropolitan areas including West Palm Beach and Melbourne are within commuting distance to the site, and a 100 mile radius includes all or part of the large cities of Fort Lauderdale to the south, and Orlando to the north.

Given the expected population of the commuting workforce, the fact that during the 22 month construction period most workers will be onsite for less than the total construction period, an abundance of hotel and other short-term lodging options, and a reported rental vacancy rate of nearly 12 percent in the area, it is unlikely that a substantial number of the TCEC construction workforce would choose to relocate during the 22 month construction period. Therefore, the anticipated housing growth will be minimal or nonexistent, and is not expected to have a significant impact on the air quality.

Commercial/Industrial

Compared to the state of Florida in general, the Treasure Coast region is expected to realize higher annual growth rates in the government sector (1.21 percent versus 0.83 percent), the wholesale trade sector (2.37 percent versus 1.88 percent), and in the health services sector (3.27 percent versus 2.73 percent). The state is projected to realize a higher annual average growth rate than the Treasure Coast area in a number of categories, including the agriculture, forestry, and fishing sector (1.22 percent versus 0.98 percent), and in the finance, insurance, and real estate sector (1.69 percent versus 1.12 percent).

Ft. Pierce is also realizing noticeable economic and employment growth. The 2003 Comprehensive Annual Financial Report for FPUA listed a number of new investments that will add jobs and demand for power to the area. This included 1,200 new jobs associated with a new Wal-Mart Distribution Center that is now operational (and located across Glades Cutoff Road from the TCEC site), the Harbour Isle project that was projected to add in excess of 800 electric, water, and wastewater accounts during the subsequent 3 years, and several new or revitalized commercial buildings.

According to the Department, there are 11 facilities in St. Lucie County that are required to have a Title V air operating permit as major air emission sources. Such operating permits are required to be in compliance with the rules set forth in Rule 62-4, F.A.C. A list of the 11 facilities in St. Lucie County that are required to have a Title V air operating permit is presented in the following table.

Owner/Company Name	Site Name	City
Ft. Pierce Utilities Authority	FPUA/H.D. King Power Plant	Ft. Pierce
Tropicana Products, Inc.	Tropicana Products	Ft. Pierce
Cargill Juice North America	Ft. Pierce	Ft. Pierce
Atlantic Coast Recycling, Inc.	Atlantic Coast Recycling	Ft. Pierce
Florida Gas Transmission Company	FGTC Compressor Station 20	Ft. Pierce
Arch Mirror South Inc.	Arch Mirror South	Ft. Pierce
S2 Yachts, Inc.	S2 Yachts	Ft. Pierce
St. Lucie County	St. Lucie Co/Glades Road Landfill	Ft. Pierce
Maverick Boat Company, Inc.	Maverick Boat Company	Ft. Pierce
Twin Vee Powercats	Twin Vee Powercats	Port St. Lucie
Twin Vee Powercats, Inc.	Twin Vee Powercats, Inc., Ft. Pierce	Ft. Pierce

Commercial/Industrial Growth Associated with the Project

The TCEC is proposed to meet the existing and current projected electrical demands of the surrounding area. It is anticipated that little commercial growth will be associated with its specific operation. Additionally, the electrical generating capacity created by the TCEC will not have a significant effect upon the industrial growth in the immediate area, considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host. For these reasons, the TCEC is not expected to have a significant impact on the air quality as the result of commercial or industrial growth.

Comment FDEP/BAR-8

In the application, Vegetation and Soils are addressed in Section 5.2. PSD pollutants, SO_2, PM/PM_{10} and NO_x are briefly mentioned. How will the other applicable PSD pollutants, SAM and CO, affect the vegetation and soils? How will all applicable PSD pollutants affect wildlife?

Response to FDEP/BAR-8

The applicable PSD pollutants for the TCEC project include SO_2, PM/PM_{10}, NO_x, CO, and sulfuric acid mist (SAM). As the Department acknowledges in their comment, FMPA has already assessed the potential air quality impacts to vegetation and soils for the PSD pollutants SO_2, PM/PM_{10}, and NO_x. The assessment was based on predicted air pollutant concentrations derived from a comprehensive air dispersion modeling analysis of the stack emissions from the proposed TCEC project. The model-predicted pollutant concentrations were compared to ambient air quality standards, which are designed to protect the public health, welfare, and the natural environment. These ambient air quality standards have been established by the USEPA for the six criteria air pollutants and include primary ambient air quality standards, which are designed to protect public health with an adequate margin of safety, and secondary ambient air quality standards, which are designed to protect public welfare-related values, including property, materials, and *plant and animal life*. In Florida, ambient air quality standards at least as stringent as the national secondary standards have been adopted by the Department.

As described in Sections 4.3 and 5.2 of the application, the model-predicted ambient concentrations of SO_2, PM/PM_{10}, NO_x, and CO are not only one or more orders of magnitude less than the applicable ambient air quality standards, but are even less than the more stringent NSR/PSD significant impact levels and the USEPA recommended screening levels for air pollution impacts on plants, soils, and animals. Because the TCEC proposed air quality impacts are so much lower than the air quality standards designed to protect plant and animal life, it is reasonable to conclude that the proposed emissions of SO_2, PM/PM_{10}, NO_x, and CO will not significantly affect vegetation, soils, or wildlife.

The air quality impact to soils, vegetation, and wildlife from SAM is also expected to be insignificant. There is no national or state air quality standard for SAM to compare model-predicted impacts with, as a general measure of SAM's air quality impact potential, as there are for other PSD pollutants. However, based on the fact that the TCEC proposes to use two of the least sulfur bearing fuels available (i.e., natural gas and ultra-low sulfur fuel oil) and that predicted SO_2 concentrations are orders of magnitude less than

USEPA recommended screening concentrations, it is reasonable to assume that SAM emissions from TCEC will not significantly impact the air quality in a manner that is detrimental to soils or vegetation.

The literature about air quality impacts on wildlife generally focuses on acute exposure by wildlife to unusual or high concentrations of pollutants. Wildlife can be affected through three pathways: ingestion, dermal exposure, and inhalation of ambient air, with ingestion, which can result in bioaccumulation, being the most common means of exposure to high concentrations of pollutants. However, the project air emissions and impacts are predicted to be very low, and are highly unlikely to have any effects on wildlife in the vicinity of the project.

Comment FDEP/SE-1

What environmental assessments have been conducted or will be conducted in order to determine whether soil, sediments, groundwater, or surface waters have been adversely affected (contaminated) by the agricultural operations? Some agricultural operations have had a historical usage of, among other things, arsenical-based pesticides and herbicides. Part of the environmental assessment must include, among other things, the details of historical and current pesticide usage, identification, including detailed, scaled maps, of current and historical fertilizer and pesticide/herbicide mixing areas, locations of canals and surface water bodies, locations of any aboveground, underground or temporary storage tanks, farming equipment maintenance and storage, petroleum product storage, onsite landfill/solid waste disposal areas, locations and types of any water production wells (potable, pesticide makeup, irrigation, etc.), locations and types of surface water pumps and associated fuel tanks, etc. What soil, sediment, surface water, and groundwater cleanup concentrations would be proposed? Are there monitoring wells available for sampling of groundwater? If so, does the facility sample and monitor groundwater from these wells? Please provide a list of the monitored parameters and the results from the sampling and enclose a map depicting these groundwater monitoring wells.

Response to FDEP/SE-1

Kimley-Horn and Associates, on behalf of the Ft. Pierce Utilities Authority (FPUA), conducted Phase I and Phase II Environmental Site Assessments in accordance with ASTM Standard E 1527-00 on the TCEC site in 2004 prior to sale of the site to FMPA. No activities have occurred onsite since that sale other than cattle grazing. Summaries of these reports are provided below; copies can be provided upon request.

The results of the Phase I investigation identified two onsite and two offsite Recognized Environmental Conditions (REC). First, the site has been in agricultural use (row crops, nursery, pasture), a REC due to potential fertilizer and/or pesticide use, since the 1950s. Two groundwater monitoring wells were located in the north-central portion of the site, believed to have been installed in 1997 in response to a small fuel spill (55 gallon drum) noted north of the site. It was also believed that the spill was cleaned up and monitoring conducted, although evidence of the cleanup or monitoring results was not located; therefore, this is a REC. The St. Lucie County Landfill, approximately 0.3 mile west of the site, had unresolved compliance issues at the time of the Phase I report and, therefore, was considered a REC. The industrial facilities on Glades Cutoff Road near the site had underground storage tanks at one time, but these tanks have since been removed. Kimley-Horn recommended an onsite Phase II investigation consisting of soil and groundwater sampling to investigate the known RECs.

Kimley-Horn conducted the Phase II sampling using standard methods, procedures, and approved laboratories to examine the noted RECs. Groundwater samples from the surficial aquifer were collected from seven existing and temporary wells. Eight background and sample soil samples were also collected. Figure FDEP-1 included in Appendix G indicates the groundwater and soil sampling locations. No additional samples have been collected since the 2004 Phase II study to FMPA's or FPUA's knowledge.

The Phase II groundwater sampling results are provided in Table FDEP-3 (Appendix G). In summary, no herbicides, organophosphorous pesticides, PCBs, TRPH, PAH, VOC, chlorinated pesticides, nitrogen, ammonia, chlorides, TDS, or metals other than iron, which was determined to be natural background, were detected in the groundwater samples at concentrations either above the laboratory analytical detection limits or greater than the Groundwater Cleanup Target Levels in Chapter 62-777, F.A.C.

The Phase II soil sample results are provided in Table FDEP-4 (Appendix G). In summary, no herbicides, organophosphorous pesticides, PCBs, chlorinated pesticides, nitrogen, ammonia, chlorides, TDS, or metals were detected in the soil samples at concentrations either above the laboratory analytical detection limits or greater than the Soil Cleanup Target Levels in Chapter 62-777, F.A.C.

The Phase I and Phase II studies, sample results, and other available information suggest that the site was not historically used as a heavy commercial or intensive agricultural property. With no direct evidence of soil or groundwater contamination, aboveground or belowground storage tanks, farming equipment/chemical/pesticide storage or mixing, onsite solid waste disposal, or irrigation facilities, FMPA believes that the site and adjacent resources/properties have not been adversely affected (contaminated) by past or current agricultural operations.

Comment FDEP/SE-2

Page 2-9 states that the existing site is pasture land. Historical cattle ranching operations may have had cattle dip vats to control diseases. An environmental investigation should be initiated in order to determine the current or historical presence of cattle dip vats at the site associated with ranching operations. Such vats, when identified, would require assessment and probable cleanup.

Response to FDEP/SE-2

There is no current or past evidence, or recent onsite observations, indicating that cattle dipping vats exist or existed on the TCEC site. The Phase I and Phase II Environmental Site Assessment reports mentioned in the above response provide no evidence that such vats ever existed. Prior to the relatively recent use as pasture, the site was used for row crop production (tomatoes). The TCEC site is not on the list of known cattle dipping vats in St. Lucie County, reviewed at
www.dep.state.fl.us/waste/quick_topics/publications/wc/cattlevats.pdf.

Comment FDEP/SE-3

What reasonable assurances can be provided to show that onsite water production wells and dewatering will not affect any off-property soil/groundwater contaminated areas? Page 4-8 lists some potential impact from "low scoring" petroleum facilities. Detailed information needs to be provided, including a map(s), showing these contaminated areas and any potential affects new withdrawals, storm water discharges, dewatering, etc. could affect. The St. Lucie County Glades Road Landfill is currently undergoing contamination assessment and that facility has a permitted zone of discharge in their Solid Waste Permit, issued pursuant to, among others, Chapters 62-701, 62-520 and 62-522, Florida Administrative Code (F.A.C.). Page 4-9 does not mention this facility.

Response to FDEP/SE-3

TCEC operations will have no adverse impact on the surficial aquifer. Operations will not withdraw from or discharge to the surficial aquifer (0 to 100 feet bgs), as stated in Subsection 5.3.2.1 of the SCA, other than seepage from the storm water detention basin, which receives only uncontaminated storm waters. The storm water basin will discharge onsite. This discharge will sheet flow in a southerly direction approximately 350 feet through onsite Wetland F1 and Wetland E, and across the FPL easement, before reaching NSLRWCD Canal 102. This sheet flow will slowly release treated storm water to the wetlands and recharge the surficial aquifer as it flows toward the canal. Groundwater production wells will withdraw from the confined Upper Floridan Aquifer, which is separated from the surficial aquifer by the 300 foot thick Hawthorn Group. The top of the Upper Floridan Aquifer is estimated at 500 feet bgs. Therefore, operational storm water discharges and withdrawals from the confined aquifer should have no adverse impact on the surficial aquifer or cause contaminant migration within the surficial aquifer from the known contaminated sites. Figure FDEP-2 and Table FDEP-5 indicate the known contamination sites in the project area; the figure, table, and Facility Inspection Sheets for the facilities are provided in Appendix H.

As discussed in Section 4.3 of the SCA, the site will be dewatered during project construction. Although the final dewatering plans will be provided by the dewatering contractor, project excavations are estimated to be relatively shallow: to approximately 4 feet in the power block area; 10 to 20 feet for specific structures. Dewatering volumes are estimated at 0.8 million gallons per day (mgd) for the initial 30 day dewatering period. After the initial 30 days, surficial groundwater levels should stabilize and dewatering volumes should decrease to 0.4 mgd. The maximum radius of influence of the construction dewatering is estimated to be less than 350 feet from the well points. Therefore, groundwater in the vicinity of the existing St. Lucie County Glades Road Landfill, which is approximately 1,800 feet from the site, is not anticipated to be impacted by the site construction dewatering.

Pursuant to SFWMD requirements, impacts of dewatering on surficial aquifer conditions, including potential migration of contaminants, will be fully analyzed and addressed prior to construction as a requirement of post-certification condition compliance.

Comment FDEP/SE-4

Section 3-7, pgs 3-28, 3-29, and 3-30. Please be advised that hazardous waste determinations are required for most wastewaters generated (including "washdowns") in accordance with Title 40 Code of Federal Regulations (C.F.R.) Part 261, as referenced in Chapter 62-730, F.A.C. In addition to any industrial waste treatment and monitoring requirements, all waste streams must be characterized for proper hazardous waste management in accordance with 40 C.F.R. Part 261, including wastes collected in sumps, laboratory wastes and material from solids settling basins. Page 4-4 has a chart and description of waste streams. The chart and a description needs to be included that indicates which waste stream would be hazardous, whether it is based on process knowledge or will be based on analytical testing, and if hazardous, additional information regarding how the facility would manage the storage and treatment of such wastes in accordance with Chapter 62-730, F.A.C., which references portions of Title 40 C.F.R. Parts 260-271, would be required.

Response to FDEP/SE-4

The wastewater generated during normal operation as shown on the revised water mass balances (i.e., cooling tower blowdown, HRSG blowdown, RO reject, evaporative cooler blowdown, oil/water separator treated effluent, and sanitary wastewater) will not meet the definition of a hazardous waste under the cited Department and USEPA rules, based on process knowledge and experience with similar power plants.

Other potential wastes generated during operations/maintenance, as originally mentioned in Section 5.4 of the SCA, include the following. The expected characteristics are based on process knowledge:

- Waste oil from oil/water separator - Expected to be hazardous and will be hauled offsite by a licensed contractor.
- Wastewater from combustion turbine drain tank - May be hazardous and will be hauled offsite by a licensed contractor (assumed hazardous).
- Wastewater in laboratory drains collection tank - May be hazardous and will be hauled offsite by a licensed contractor (assumed hazardous).
- Wastewater from offline chemical cleaning of RO system membranes - Based on typical chemicals used for cleaning, expected to be nonhazardous. If verified to be nonhazardous based on regulation, MSDS, or manufacturer's recommendation, it will be disposed to the FPUA wastewater system injection wells. If potentially hazardous based on regulation, MSDS, or manufacturer's recommendation, it will be hauled offsite by a licensed contractor.
- Chemical sumps - Spillage will be assessed based on regulation, MSDS, or manufacturer's recommendation for the chemical. If potentially hazardous, it will be recovered back to the tank or hauled offsite by a licensed contractor. Normal washdown and rainwater collected in curbed areas will be nonhazardous and will be disposed to the plant wastewater system to the FPUA injection wells.
- HRSG chemical cleaning - Expected to be nonhazardous. This will be verified by TCLP test. If nonhazardous, it will be disposed to the FPUA wastewater system injection wells. If hazardous, it will be hauled offsite by a licensed contractor.

- Cooling tower drain and clean - Expected to be nonhazardous. It will be disposed to the FPUA wastewater system injection wells.
- Oily solid waste/rags - Considered hazardous and will be hauled offsite by a licensed contractor.
- Waste solvents and paints - Considered hazardous and will be hauled offsite by a licensed contractor.
- Miscellaneous solid wastes, such as wood, metals, plastics, and office waste - Will be collected and contained onsite and disposed by a licensed recycling or disposal facility.
- Spent SCR catalyst - Considered hazardous and will be removed and promptly disposed of offsite by the catalyst supplier.

Regarding Page 4-4, a revised Table 4.1-1 indicating which waste streams are or may be expected to be considered hazardous is provided in Appendix I.

Comment FDEP/SE-5

Any land clearing or construction debris must be characterized for proper disposal. Potentially hazardous materials must be properly managed in accordance with Chapter 62-730, F.A.C. In addition, any solid wastes or other non-hazardous debris must be managed in accordance with Chapter 62-701, F.A.C.

Response to FDEP/SE-5

FMPA will develop procedures to properly manage land clearing debris, construction debris, and hazardous materials/wastes during construction of TCEC Unit 1. These procedures will address worker training, inspections and recordkeeping, spill prevention and response, materials storage, and hazardous waste determinations. If any waste is questionable, FMPA will require the use of the EPA's Toxic Characteristic Leaching Procedure (TCLP) to determine whether a waste is hazardous. Although FMPA will not be an owner or operator of a solid waste disposal facility at the TCEC site, FMPA will require all contractors to comply with the applicable regulations in Chapter 62-701, FAC. FMPA will also develop a Hazardous Waste Management Plan and Chemical Management Procedures Plan to order, store, track, and determine hazardous qualities in accordance with Chapter 62-730, FAC. FMPA anticipates classification as either a Conditionally Exempt Small Quantity Generator or Small Quantity Generator during both construction and operation of TCEC Unit 1. Contractors onsite during both construction and operation will be required to manage their hazardous materials and wastes in accordance with the established FMPA procedures and plans.

Comment FDEP/SE-6

Petroleum and hazardous materials storage tanks and emergency generators for planned facilities must be constructed to comply with the current requirements of Chapter 62-761 and/or 62-762, F.A.C. An acknowledgment that these facilities would comply with the applicable requirements of these rules should be included. As an example, secondary containment should be planned for all areas where petroleum or hazardous materials discharges could affect soils, sediments, surface or ground waters.

Response to FDEP/SE-6

FMPA will design and construct all underground and aboveground storage tanks, and secondary containments, in accordance with the current requirements of Chapters 62-761 and/or 62-762, F.A.C.

FMPA will also prepare and implement a Spill Prevention, Control and Countermeasure (SPCC) Plan for the operating facility.

Comment FDEP/SE-7

The applicant states that they will be using water from the Floridan Aquifer. The applicant has applied for 6 wells at a depth of @ 500 feet. The operation of these wells will cause a drawdown of the water table several thousand feet away. Within 1,800 feet of this proposed site is the existing St. Lucie County Glades Road Landfill. The landfill is under a Consent Order performing CAP/CAR/RAP for offsite contamination at the east and northeast portion of the landfill property boundary in the shallow aquifer (@ 20 to 40 feet in depth) from the old unlined Class I landfill located at the intersection of I-95 and the Fla. Turnpike. The groundwater flows northeast in this area. The applicant also proposes to do dewatering via a GP to the SFWMD. The applicant needs to demonstrate that the proposed dewatering and proposed production wells will not affect the landfill plume or draw the landfill plume to the applicant's or other adjacent properties. The applicant should also demonstrate that the shallow production zone and Floridan aquifer are not connected.

Response to FDEP/SE-7

FMPA has requested approval of only three (3) wells at this time. TCEC well withdrawals during operation will have no impact on the surficial aquifer. Groundwater production wells will withdraw from the confined Upper Floridan Aquifer, which is separated from the surficial aquifer by the 300 foot thick Hawthorn Group. Operations will not withdraw from or discharge to the surficial aquifer (0 to 100 feet bgs), as stated in Subsection 5.3.2.1 of the SCA, other than seepage from the storm water detention basin, which receives only uncontaminated storm waters. The top of the Upper Floridan Aquifer is estimated at 500 feet bgs. Therefore, operational well water withdrawals from the confined Upper Floridan Aquifer should have no impact on the surficial aquifer groundwater flow or cause contaminant migration within the surficial aquifer from the known contaminated sites.

As discussed in Section 4.3 of the SCA, the site will be dewatered during project construction. Although the final dewatering plans will be provided by the dewatering contractor, project excavations are estimated to be relatively shallow: to approximately 4 feet in the power block area; 10 to 20 feet for specific structures. As discussed in the response to Comment FDEP/SE-3, the maximum dewatering is estimated at 0.8 mgd for the initial 30 day dewatering period. After the initial 30 days, surficial groundwater levels should stabilize and the total dewatering volume is estimated to decrease to 0.4 mgd. The maximum radius of influence of the site dewatering pumping is estimated to be less than 350 feet. Therefore, the proposed construction dewatering is not anticipated to affect groundwater or the contaminant plume under the St. Lucie County Glades Road Landfill, which is located 1,800 feet west of the site.

Pursuant to SFWMD requirements, impacts of dewatering on surficial aquifer conditions, including potential migration of contaminants, will be fully analyzed and addressed prior to construction as a requirement of post-certification condition compliance.

Comment FDEP/BWF-1

Sections 373.250 and 403.064, F.S., establish the encouragement and promotion of water reuse as state objectives and note that reuse is in the public interest. Further, Chapter 62-40, F.A.C., requires use of reclaimed water within designated Water Resource Caution Areas. This proposed plant is located within a Water Resource Caution Area. The Department applauds the use of reclaimed water for cooling water at this facility. Part VII of Chapter 62-610, F.A.C., specifically addresses and allows for the use of reclaimed water in cooling water applications. This use of reclaimed water is consistent with statutory and rule directives and objectives. Has wastewater from the City of Port St. Lucie been considered as a source until the Fort Pierce supply is available?

Response to FDEP/BWF-1

FMPA worked closely with its members to select the most appropriate site for the new generation project, acknowledging that the use of reclaimed water, specifically for equipment cooling, would be a beneficial use of that water while conserving groundwater resources. As a result, the Ft. Pierce Utilities Authority's need for a new wastewater treatment plant and disposal site, and FMPA's need for new generation and a long-term source of cooling water were realized at the Treasure Coast Energy Center site. These facilities were compatible and mutually beneficial to FPUA and the FMPA members, and in compliance with regulatory directives and objectives.

On behalf of FMPA, Mr. Ken Weiss of Black & Veatch spoke with Mr. Wes Upham of the City of Port St. Lucie Regulatory Compliance Section on June 22, 2005, regarding the availability of reclaimed water from City facilities for use at the TCEC. Mr. Upham indicated that the Glades Wastewater Treatment Plant is currently under construction and is scheduled to go on line in late 2006. The wastewater treatment plant is located 1 mile west of Glades Cutoff in Section 17, Township 36S, Range 39E, approximately 5.5 miles southwest of the TCEC site. The plant will be rated at 4.0 mgd when fully operational and is intended to replace the existing Port St. Lucie Northport Plant. The new plant will produce highly disinfected reclaimed water through the "Bardenpho" process. This process includes biological nitrogen and phosphorus reduction.

FMPA acknowledges the construction of this facility and potential availability of reclaimed water. However, section 373.250(2)(b), Florida Statutes, provides that the City of Port St. Lucie's reclaimed water is not presumed available because the City will not provide the reclaimed water distribution facilities to the TCEC site at the City's expense. In addition, section 373.250(2)(c), Florida Statutes, requires the use of reclaimed water only when economically feasible. It is not economically feasible for FMPA to construct distribution facilities from the City of Port St. Lucie's Glades Wastewater Treatment Plant. For FMPA to install a pipeline to deliver reclaimed water from the Glades WWTP, FMPA would significantly add to the capital and operating cost of the TCEC project to realize a limited short-term environmental benefit until the FPUA wastewater treatment plant comes online by June 2009. The estimated capital cost to install and operate a pipeline and pumping system (including pumps, pumps structure, electrical, controls, pipeline, and rights-of-way) is approximately $4 million. Note Rule 62-40.416(1), F.A.C., provides that the economic feasibility of reusing reclaimed water shall consider the costs and benefits of such use.

Comment FDEP/BWF-2

Has reclaimed water been considered for use in the fire protection system or for toilet flushing purposes? Please note that Part III of Chapter 62-610, F.A.C., allows the use of reclaimed water for toilet flushing, fire protection, and other uses. Both of these are excellent uses of reclaimed water and should be incorporated into the project, if feasible.

Response to FDEP/BWF-2

Reclaimed water is not expected to be available for the project until June 2009. Therefore, the fire protection water will be well water and toilet flushing water supply will be potable water. After reclaimed water is available, the feasibility of converting these systems will be evaluated as part of the anticipated water conservation plan for SFWMD.

Comment FDEP/BWF-3

In accordance with Rules 62-610.660 and 62-555.360, F.A.C., the SCA should evaluate the need for backflow prevention devices on reclaimed water and potable water lines to prevent either source from being contaminated.

Response to FDEP/BWF-3

The potable and reclaimed water systems will be furnished with backflow prevention in accordance with state and local regulations. Potable water is not used for any process purpose except as supply to the evaporative coolers and backup supply to the service/fire water tanks. The supply connections to the evaporative coolers and the backup supply to the service/fire water tanks will be furnished with air gap backflow prevention systems.

Comment FDEP/BWF-4

The first generating unit at the power plant (Unit 1) is scheduled to begin commercial operation in June 2008, pending certification and construction. According to the SCA, the POTW is expected to be operational by "late 2009." The SCA text and the water mass balances indicate that the injection wells are the only means of disposal for wastewater from the power plant, so the wells have to be permitted, constructed, and in operation for the power plant to operate. There did not appear to be a schedule for the injection wells at the POTW. The applicant needs to clarify this point and provide demonstrate that the power plant will have a means for disposal of cooling tower blowdown, other process wastewaters, and domestic wastewater.

Response to FDEP/BWF-4

FPUA's schedule for operation of the injection wells (process wastewater disposal) is December 1, 2007, and June 5, 2009, for operation of the Mainland Water Reclamation Facility (reclaimed water supply). An alternative disposal option is available if for some reason the injection wells are not available. During TCEC construction and startup, FMPA will have the option to dispose of wastewaters to the existing 6 inch FPUA force main in the southern portion of the TCEC site which transports wastewaters to the Hutchinson Island Wastewater Treatment Plant. However, this main will not have sufficient capacity for the entire wastewater flow during normal operation.

Comment FDEP/BWF-5

How will power plant operations be impacted if the POTW cannot provide sufficient reclaimed water long-term due to slower than expected population growth or other factors?

Response to FDEP/BWF-5

FPUA has confirmed to FMPA that they can provide the long-term reclaimed water requirement, as stated in the FPUA letter of commitment included in Appendix K. For potential future generating units at TCEC, the water supply will be verified as part of the Supplemental Site Certification process. During periods when treated wastewater is not available from FPUA, water will be withdrawn from the Upper Floridan Aquifer, as proposed in the SCA.

Comment FDEP/BWF-6

How will power plant operations be impacted when injection wells at the POTW are out of operation for mechanical integrity testing or other maintenance activities? Will they have multiple wells?

Response to FDEP/BWF-6

FPUA has indicated to FMPA that they will have permitted facilities in case of well outage. Note that FPUA will also need these provisions for disposal of treated sanitary wastewater from the new FPUA wastewater plant. FPUA's letter of commitment, included in Appendix K, indicates these provisions.

Comment FDEP/BWF-7

Section 3.6.2 implies that a force main to the unbuilt FPUA plant already exists. Is this correct?

Response to FDEP/BWF-7

There is an existing 6 inch FPUA force main in the southern portion of the TCEC site, approximately 175 feet north of the north edge of the Devine Road right-of-way. This line currently transports sanitary wastewater to the Hutchinson Island Wastewater Treatment Plant. It is expected that the TCEC sanitary wastewater destination will be revised when the new FPUA WWTP goes into service.

Comment FDEP/BWF-8

Figure 3.5-6 shows 942,000 gpd as the annual average of wastewater going to the injection well, not the 889,000 gpd reported in the text. Please clarify.

Response to FDEP/BWF-8

Figure 3.5-6 (Water Mass Balance-9) indicates the annual average when well water is used as cooling tower makeup. Because of differences in water quality, more blowdown is required when using well water makeup rather than reclaimed water in order to maintain water quality in the circulating cooling water system and the cooling tower.

Also for water quality reasons, FMPA will use potable water from FPUA in the evaporative cooler rather than well water. Revised water mass balances indicating this change are included Appendix L.

Comment SFWMD-1

Please specify the water supply quantity/source for dust control.

Response to SFWMD-1

The construction project will use water from the FPUA municipal system for dust control. During the first 2 months of site grading and filling, use of 6,000 gpd, 5 days per week, is estimated for dust control. For the following 16 months, use is estimated at 3,000 gpd into plant startup, then 1,000 gpd for the final 4 months to commercial operation.

Comment SFWMD-2

Please submit the details of the proposed wells as required in Table A (Form 0645-G-60).

Response to SFWMD-2

Details of the well design are not available at this time. FMPA will accept a Condition of Certification requiring the submittal and approval of detailed well design information prior to well construction.

Comment SFWMD-3

The calculations provided in response to Section F.1 of the Water Use Permit Application Form indicate that the values are based on using groundwater for cooling for Unit 1. Section G.1 of the Supporting Information states that, excluding the cooling system, 597,000 gallons per day of water are required for Unit 1. Please provide a breakdown of all of the water use demand using the appropriate tables, including Table D (Form 0645-G-65), Table G (Form 0645-G-69), and Table I (Form 0645-G-71).

Response to SFWMD-3

The breakdown of water used is covered in Section 3.5 of the SCA. For additional clarification using the forms, please refer to the attached copies of Table E, Table G, and Table I. Table D is not applicable to this industrial facility (no irrigation proposed). Table G is not directly applicable to an industrial facility, but has been included to provide information on the expected well water consumption by year. These tables are provided in Appendix M.

The groundwater allocation request has been revised due to changing the evaporative cooler makeup water source from groundwater to potable water, as previously mentioned in Response FDEP/BWF-8. Daily, monthly, and 90-day requests are now slightly less than originally requested. In addition to the tables, a revised water use estimate is also included in Appendix M.

Comment SFWMD-4

The groundwater modeling must follow the criteria set forth in Section 1.7.5.2 of the Basis of Review (BOR) for Water Use Permit Applications. Please note that the extrapolation of site-specific characteristics from a calibrated model is not in accordance with SFWMD criteria. Please submit revised modeling that meets the requirements set forth in Section 1.7.5.2 of the BOR..

Response to SFWMD-4

FMPA representatives discussed this sufficiency question with SFWMD (Steve Memberg) on July 7, 2005 during which the only issue raised was the need to obtain aquifer characteristics from aquifer performance tests (APTs). In response, FMPA compiled existing aquifer performance test (APT) data from the SFWMD DBHYDRO database and discussed the Upper Floridan Aquifer parameters for the Treasure Coast site with SFWMD. During the discussion, FMPA and SFWMD agreed to the aquifer parameters and the impact evaluation procedure. The following items were completed after the discussion:

- The impact assessment was completed using the Theis equation. A transmissivity value of 41,349 ft^2/day and storativity value of 0.00061 were used for the Upper Floridan Aquifer.
- 90 day maximum pumping drawdown was evaluated The assessment was based on pumping rates of 3.555 mgd for 500 hours of plant operation on oil and 3.324 mgd on gas for 1,660 hours for one unit operation.

The assessment results are included in Appendix J. The maximum calculated drawdowns are 5.7, 4.4, and 3.67 feet at one, two, and three mile distances from the site, respectively. A one foot drawdown due to the site's maximum pumping is estimated at a distance of 14.4 miles from the site. The estimated additional drawdown due to the maximum plant pumping at the Port St. Lucie water supply wells is 5.2 feet.

FMPA and their Consultants have discussed the cumulative impact issue with District staff. FMPA is preparing a supplemental response to the cumulative impact issue and will submit that response to the District under separate cover.

Comment SFWMD-5

Please submit a letter from the Fort Pierce Utilities Authority (FPUA) documenting the availability of reclaimed water for the proposed project, as required by Section G.1.4 of the Water Use Permit Application Form.

Response to SFWMD-5

A copy of FPUA's letter of commitment to provide reclaimed water is provided in Appendix K. In addition, a table of projected wastewater flows from the Ft. Pierce Utilities Authority is also provided in Appendix K.

FMPA investigated the potential use of reclaimed water from the City of Port St. Lucie. However, as explained in Response FDEP/BWF-1, the use of reclaimed water from this source is not considered feasible.

Comment SFWMD-6

Please supply a letter from the FPUA documenting the availability of potable water for the proposed project, pursuant to the discussion on page 6 of the Additional Information in Support of TCEC Industrial Water Use Request.

Response to SFWMD-6

A copy of FPUA's letter of commitment to provide potable water is provided in Appendix K.

Comment SFWMD-7

The SCA indicates that the details of the proposed dewatering activities will be submitted during the post-certification review process. Please be advised of the following:

Comment SFWMD-7a

Section D.4 of the Dewatering Permit Application and Section 4.4.1 of the Site Certification Application state that wetlands will remain onsite. In addition, wetland areas are present within the surrounding project area. As per Section D.5 of the Dewatering Permit Application, modeling or specific engineering controls that include recharge trenches may be necessary to provide reasonable assurances that no harm occurs to wetland areas due to the proposed withdrawals or discharges.

Response to SFWMD-7a

Detailed dewatering plans are not available at this time. FMPA will accept a Condition of Certification requiring the submittal and approval of detailed dewatering plans prior to initiating dewatering activities.

Comment SFWMD-7b

A known contaminated facility is located approximately 400 feet east of the project site (Florida Department of Environmental Protection Facility ID No. 8631089). As per Section E.1 of the Dewatering Permit Application, modeling may be necessary to provide reasonable assurances that there are no adverse impacts due to the proposed withdrawals or discharges.

Response to SFWMD-7b

Black & Veatch, on behalf of FMPA, contacted Mr. David Koerner of the St. Lucie County Health Department to request the information sheet on the Southern Eagle Distributors site (Facility No.

8631089). The Facility Inspection sheet is included in Appendix H. Mr. Koerner indicated that Southern Eagle is under the state Early Detection Incentive cleanup program. Southern Eagle was first listed on 12/8/88, and the cleanup status is now inactive. The six (6) underground storage tanks have been closed and removed; the two (2) aboveground storage tanks are still active (U means open/active and B means closed on the inspection sheet under Status). The cleanup priority is a 6, which is very low.

FMPA believes that the Southern Eagle site no longer provides a contamination threat, and that TCEC site dewatering will not cause adverse impacts or contaminant migration within the local surficial aquifer.

Comment SFWMD-7c

The licensee must submit calculations showing that the detention basin has sufficient capacity to accept dewatering effluent.

Response to SFWMD-7c

The calculation demonstrates that at a dewatering flow rate of 0.8 mgd, the stormwater collection area will detain the water for 39 hours. This indicates that the stormwater collection area can manage the daily dewatering volume, and allow for settlement time prior to discharge.

Due to Site Arrangement revisions, the storm water calculations were rechecked to consider the additional impervious area. The calculation provided in Appendix N demonstrates that the updated Site Arrangement does not affect the overall storm water design. The composite curve number used on the initial design was 86.7, and with the new layout, the curve number is 79.0. Since the curve number has been reduced, the capacity development area established in the initial calculation is sufficient to meet all design requirements.

Appendices

Appendix A	SCA Figure 2.3-5. FLUCCS Land Use
Appendix B	Report on Compliance with Electric and Magnetic Field (EMF) Standards
Appendix C	Table FDEP-1. GE Emissions Guarantees
Appendix D	Revised Site Arrangement
Appendix E	Air Quality Impact Tables
Appendix F	Table FDEP-2. PSD Applicability Comparison
Appendix G	Figure FDEP-1. Groundwater and Soil Sample Locations
	Table FDEP-3. Groundwater Sampling Results
	Table FDEP-4. Soil Sampling Results
Appendix H	Figure FDEP-2. Contaminated Sites Location Map
	Table FDEP-5. Contaminated Sites in Vicinity of TCEC
	Facility Inspection Sheets
Appendix I	Table 4.1-1. Waste Streams and Wastewater Streams Associated with Construction
Appendix J	Groundwater Impact Assessment Results
Appendix K	FPUA Letter of Commitment
Appendix L	Revised Water Mass Balances
Appendix M	Water Use Tables
	Revised Water Use Request
Appendix N	Dewatering and Storm Water Basin Calculations

Table FDEP-1. GE Emissions Guarantees

Natural Gas Fuel:

Measurement	Guaranteed Value	Load Range %	Ambient Range °F
NO_x @ 15% O_2 (ppmvd)	9.0	60 - 100	26 - 100
CO (ppmvd)	5.0	50 - 100	35 - 85
	"	60 - 100	>85 - 100
	9.0	50 - < 60	>85 - 100
	"	50 - 100	26 - <35
UHC (ppmvw)	7.0	60 - 100	26 - 100
VOC (ppmvw)	1.4	60 - 100	26 - 100
PM/PM_{10}, front half plus back half with sulfur (lb/h)	18	N/A	N/A

Distillate Oil:

Measurement	Guaranteed Value	Load Range %	Ambient Range °F
NO_x @ 15% O_2 (ppmvd)	42	60 - 100	26 - 100
CO (ppmvd)	8.0	75 - 100	26 - 100
	20.0	50 - <75	26 - 100
UHC (ppmvw)	7.0	60 - 100	26 - 100
VOC (ppmvw)	2.0	75 - 100	26 - 100
	3.5	50 - <75	26 - 100
PM/PM_{10}, front half plus back half with sulfur (lb/h)	34	N/A	N/A

Table FDEP-2. PSD Applicability Comparison (Project)[1]						
	Using an Ambient Temp. of 73° F			Using an Ambient Temp. of 59° F		
Pollutant	Annual PTE (tpy)	PSD SEL (TPY)	PSD Major (Yes/No)	Annual PTE (tpy)	PSD SEL (TPY)	PSD Major (Yes/No)
NO_x	88.9	40	Yes	91.0	40	Yes
CO	228.7	100	Yes	234.7	100	Yes
PM	175.9	25	Yes	176.5	25	Yes
PM_{10}	171.3	15	Yes	171.8	15	Yes
SO_2	56.5	40	Yes	57.8	40	Yes
VOC	23.3	40	No	23.3	40	No
SAM	22.4	7	Yes	23.0	7	Yes

[1]Note that this table illustrates the affect of ambient temperature on PSD applicability. Because PSD applicability is based on the Project potential to emit (PTE), the project PTE values are shown in this table. Only the CT emissions are affected by ambient temperature, so the differences in PTE between the ambient temperature cases shown in this table are equivalent to the differences in the TCEC Unit 1 PTE. Also note that this Table reflects elimination of the auxiliary boiler from the Project, as discussed in the Response to FDEP/BAR-4. Therefore, the values shown above (for the 73° F case) will be slightly lower than the values given in Table 2-2 of the application.

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

April 21, 2005

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division007-AC
P. O. Box 25287
Denver, Colorado 80225

RE: Florida Municipal Power Agency
Treasure Coast Energy Center
1110121-001-AC, PSD-FL-353

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Florida Municipal Power Agency for construction of the Treasure Coast Energy Center in Fort Pierce, St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Cindy Mulkey, review engineer, at 850/921-8968.

Sincerely,

Patty Adams
for A. A. Linero, P.E., Administrator
South Permitting Section

AAL/pa

Enclosure

cc: C. Mulkey

item 4 if Restricted Delivery is desired.
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1. Article Addressed to:

Mr. Roger A. Fontes, General Manager
and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) SHARON ADAMS

C. Date of Delivery 6-1-06

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If YES, enter delivery address below: ☐ No

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Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

PS Form 3800, May 2000 See Reverse for Instructions

AQ / Cindy M

FMPA

Florida Municipal Power Agency

Susan Schumann
Environmental Specialist

July 28, 2006

RECEIVED
JUL 31 2006
BUREAU OF AIR REGULATION

Hamilton S. Oven, Administrator
Office of Siting Coordination
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Fl 32399

Re: **Florida Municipal Power Agency / Treasure Coast Energy Center (TCEC) Site Certification PA 05-48 / Conditions of Certification for Commencement of Construction**

Dear Mr. Oven:

In compliance with Condition of Certification XII.D of Site Certification Order PA 05-48 issued for the construction and operation of the Treasure Coast Energy Center Unit 1, the Florida Municipal Power Agency (FMPA) is, through the transmittal of this letter, providing Notice of Commencement of Construction for the Project. Construction is scheduled to begin on or about July 31, 2006.

If you have any questions about the project or this submittal, please contact me at (407) 355-7767 or via email at susan.schumann@fmpa.com .

Sincerely,

Susan Schumann

Susan Schumann
Florida Municipal Power Agency

Cc: Jim Golden, SFWMD
Tim Gray, FDEP SE District
Trina Vielhauer, FDEP BAR

SENDER: *COMPLETE THIS SECTION*

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1. Article Addressed to:

Mr. Roger A. Fontes, General Manager
and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [illegible] ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Sharon Adams

C. Date of Delivery 6-1-06

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and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

PS Form 3800, May 2000 See Reverse for Instructions

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Roger A. Fontes, General Manager
and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Khrisele Jones ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) | C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

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7001 0320 0001 3692 1841

Mr. Roger A. Fontes, General Manager
and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

PS Form 3800, January 2001 See Reverse for Instructions

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 1110121-001-AC, PSD-FL-353, and PA 05-48
FMPA Treasure Coast Energy Center
Combined Cycle Power Project
St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD Permit) of Air Quality to Florida Municipal Power Agency. The permit is to construct a nominal 300 megawatt (MW) combined cycle electrical power generating plant at the Treasure Coast Energy Center near Fort Pierce, St. Lucie County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400, Florida Administrative Code (F.A.C.), for emissions of particulate matter (PM/PM10), carbon monoxide (CO), sulfur dioxide (SO2), sulfuric acid mist, and nitrogen oxides (NOX). The applicant's name and address are Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida 32819.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 130 MW separate steam-electrical generator, a 170-foot stack, a mechanical draft cooling tower with drift eliminators, a 990,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up ultra low sulfur (ULS) fuel oil (0.0015 percent sulfur) will be burned for a maximum of 500 hours per year.

NOx emissions will be controlled by selective catalytic reduction (SCR) to achieve 2 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 8 ppmvd while burning ULS fuel oil. Emissions of CO will be controlled to 4.1 and 8 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM10, SO2, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and ULS fuel oil. Ammonia emissions (NH3) generated due to NOX control will be limited to 5 ppmvd.

FMPA's estimates of maximum potential annual emissions from the project are summarized in the following table.

Pollutants	Maximum Potential Emissions Tons Per Year	PSD Significant Emission Rate Tons Per Year
CO	231	100
NO_x	90	40
PM/PM_{10}	176/171	25/15
Sulfuric Acid Mist	22.4	7
SO_2	56.6	40
VOC	23.4	40
Lead	0.007	0.6
Mercury	0.001	0.1
HAPs	12.5	NA

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park and the Chassahowitzka Wilderness Area (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The project has no significant impact on the PSD Class I Chassahowitzka Wilderness and Everglades National Park areas. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 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 indicate; (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 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southeast District Branch Office
1801 SE Hillmoor Dr., Suite C-204
Port St. Lucie, Florida 34952
Telephone: 772/398-2806
Fax: 772/398-2815

Dept. of Environmental Protection
Southeast District Office
400 North Congress Avenue, Suite 200
West Palm Beach, Florida 334018
Telephone: 561/681-6774
Fax: 561/681-6755

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/treasurecoast.htm

Publish: November 4, 2005 1259989