21 West Church Street
Jacksonville, Florida 32202-3139

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SEP 18 2008

BUREAU OF AIR REGULATION

September 17, 2008

JEA

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Mr. Syed Arif, P.E.
Permit Engineer
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Greenland Energy Center Simple Cycle Turbines
Project No. 0310561-001-AC, Construction Permit Comments

Dear Mr. Arif:

Per our conversation, enclosed please find four copies each of the draft Greenland Energy Center Construction Permit, Technical Evaluation and Preliminary Determination, and Appendices with underline/strikethrough comments from JEA.

If you have any questions regarding this submittal, please call me at 904-665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Services

Attachments: As Noted.

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SEP 18 2008

BUREAU OF AIR REGULATION

PERMITTEE:

JEA – Greenland Energy Center
21 West Church Street
Jacksonville, Florida 32202

Authorized Representative:
Mr. James M. Chansler, P.E., Chief Operating Officer

Greenland Energy Center	
Two Simple Cycle Combustion Turbines	
Permit No.	PSD-FL-401
Project No.	0310561-001-AC
Expires:	December 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of two General Electric PG7241FA simple cycle combustion turbine electrical generators with a nominal output of 352 megawatts (MW) on natural gas and 380 MW on ultra low sulfur fuel oil at the new Greenland Energy Center. The new facility site is at 12121 Phillips Road, Jacksonville, in Duval 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. 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).

CONTENTS

________DRAFT_________ ____________
Joseph Kahn, Director Date
Division of Air Resource Management

SECTION I - GENERAL INFORMATION

FACILITY DESCRIPTION

The proposed facility is a new electric-generating facility referred to as Greenland Energy Center (GEC). GEC will be built in two phases. The initial phase will be the construction of two natural gas-fired simple cycle combustion turbine (CT) units that are proposed to be operational by June 2010. This permit authorizes the construction of the initial phase. The second phase will convert these simple cycle units to a combined cycle combustion turbine ("2-on 1" configuration). Heat recovery equipment will be installed on the two simple cycle combustion turbines to capture enough heat energy to run a steam turbine (ST). This second phase is proposed to be operational in June 2012. A new PSD construction permit application will be submitted for the second phase at a later date.

PROJECT DESCRIPTION

This project is for the construction of two General Electric PG7241FA simple cycle combustion turbine (CT) electrical generators (Units 1 and 2) with a nominal output of 352 MW on natural gas and 380 MW on ultra low sulfur fuel oil (ULSFO); equipped with dry low-NOx (DLN) combustors system for nitrogen oxides (NOx) reduction while burning gas and water injection while burning ULSFO. The project also includes the installation of two 1.875 million gallon, one 2,500 gallon and one 500 gallon ULSFO storage tanks, an emergency diesel fired pump, a natural gas fired process heater and an emergency generator.

Two operating scenarios are proposed that correspond to the availability of natural gas fuel onsite. Under the first scenario (Scenario 1 – Pre-Onsite Natural Gas Availability), natural gas is not available and the CT will burn ULSFO (0.0015% sulfur by weight) exclusively. The applicant requests the operation to be limited to combined ULSFO usage of 30,213 thousand gallons per year (kgal/yr), equivalent to 1,000 hours of full load ULSFO firing per year per CT. When the natural gas pipeline construction is complete (Scenario 2 – Post Onsite Natural Gas Availability) and natural gas fuel is available onsite (expected by June 1, 2010), JEA proposes to fire each CT for 3,500 hours per year with up to ~~on natural gas or 3,000 hours per year on natural gas and~~ 500 hours per year of that total on ULSFO (0.0015% sulfur by weight) and the balance on natural gas.

NEW EMISSION UNITS

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

ID	Emission Unit (EU) Description
001	Unit 1 – General Electric PG7241FA gas turbine electrical generator.
002	Unit 2 – General Electric PG7241FA gas turbine electrical generator.

This permit also authorizes construction and installation of the following emission units which are exempt from construction permitting requirements but certain new source performance standards may still apply. These emission units will be included in the Title V Operating Permit.

ID	EU Description
003	Two 1.8 million gallon, one 2,500 gallon and one 500 gallon distillate fuel oil storage tanks. This is an exempt emission unit as explained in the technical evaluation.
004	1,500 kilowatt (kW) Emergency Diesel Engine Generator and 350 brake horse power (bhp) Emergency Diesel Fire Pump. This is an exempt emission unit as explained in the technical evaluation.
005	5.84 Million British Thermal Unit per hour (MMBtu/hr) Natural Gas Fired Fuel Gas Heater. This is an exempt emission unit as explained in the technical evaluation.

SECTION I - GENERAL INFORMATION

REGULATORY CLASSIFICATION

Title I, Part C, Clean Air Act (CAA): The facility will be a PSD-major facility pursuant to Rule 62-212, F.A.C.

Title I, Section 111, CAA: Units 1 and 2 will be subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).

Title I, Section 111, CAA: EU 004 (Emergency Diesel Engine and Emergency Diesel Fire Pump) will be subject to the manufacturer's certification requirements of compliance under 40 CFR 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines).

Title I, Section 112, CAA: The facility will not be a "Major Source" of hazardous air pollutants (HAP).

Title IV, CAA: Units 1 and 2 will be subject to the Acid Rain provisions of the Clean Air Act.

Title V, CAA: The facility will be 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/particulate matter less than 10 microns (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC).

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	Citation Formats and Glossary of Common Terms
Appendix B	General Conditions
Appendix C	Common Conditions
Appendix D	Common Testing Requirements
Appendix E	Summary of Best Available Control Technology Determinations
Appendix F	NSPS Subpart A, General Provisions
Appendix G	NSPS Subpart KKKK Requirements for Stationary Combustion Turbines

RELEVANT DOCUMENTS:

The permit request and additional information received to make it complete are not a part of this permit; however, the information is listed in the technical evaluation which is issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify emissions unit should be submitted to the Bureau of Air Regulation (BAR), 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.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications should be submitted to the City of Jacksonville Environmental Resource Management Department, Environmental Quality Division, 117 West Duval Street, Suite 225, Jacksonville, Florida 32202 and a copy to the DEP Northeast District, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256.

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

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the F.S.; Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296 and 62-297 of the F.A.C.; and the Title 40, Parts 51, 52, 60, 63, 72, 73 and 75 of the 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 F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. Construction and Expiration: Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. 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(12), F.A.C.]

6. 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.]

7. Source Obligation.

   a. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. This permit authorizes construction of the referenced facilities. [Chapters 62-210 and 62-212, F.A.C.]

9. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]

10. 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.]

Unit 1 and 2 Simple Cycle Combustion Turbines (EU 001 and 002)

The specific conditions of this subsection apply to the following emissions unit after construction is complete.

ID	Emission Unit Description
001	Unit 1 – General Electric (GE) PG7241 FA gas turbine electrical generator
002	Unit 2 – GE PG7241 FA gas turbine electrical generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Units 1 and 2 are subject to determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter/particulate matter less than 10 microns (PM/PM_{10}) and sulfuric acid mist (SAM). [Rule 62-210.200 (BACT), F.A.C.]

2. NSPS Requirements: The combustion turbines shall comply with the applicable New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions) and Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005). See Appendix F for the NSPS Subpart A provisions and Appendix G for the NSPS Subpart KKKK provisions. The BACT emissions standards for NO_X and the fuel sulfur specifications for SO_2 are as stringent as, or more stringent than the NO_X and SO_2 limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts. [Rule 62-204.800(7)(b), F.A.C. and 40 CFR 60, Subparts A and KKKK]

EQUIPMENT DESCRIPTION

3. Combustion Turbine: The permittee is authorized to install, tune, operate, and maintain two GE Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 176 MW each while firing natural gas and 190 MW each while firing ULSFO. The combustion turbines will be equipped with GE's DLN combustor; Mark VI automated combustion turbine control system, and an inlet air filtration system. The combustion turbines will be designed for operation in simple cycle mode and will have dual-fuel capability. [Application and Design]

CONTROL TECHNOLOGY

4. 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 combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine when firing natural gas, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and NO_X. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or determined best practices. [Design and Rule 62-212.400(10)(BACT), F.A.C.]

5. Wet Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the combustion turbine when firing ULSFO. Prior to the initial emissions performance tests when firing ULSFO, the water injection system shall be tuned to achieve the permitted NOx emissions standard. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or determined best practices. [Applicant request and Rule 62-212.400(10)(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

6. Hours of Operation (Pre-onsite natural gas availability): The two combustion turbines are limited to a combined ULSFO usage of 30,213 thousand gallons per year. Each combustion turbine shall not operate more than 17 hours on ULSFO per calendar day for compliance with regional haze impact thresholds. The fuel usage shall be monitored with fuel meters.

{Permitting Note: The fuel usage of 30,213 thousand gallons per year for two turbines combined is equivalent to 1000 hours of operation per year per turbine.}
[Rule 62-210.200(PTE and BACT) F.A.C.; Rule 62-212.400(PSD), F.A.C. and Applicant Request]

7. Hours of Operation (Post-onsite natural gas availability): Each combustion turbine shall not operate more than 3,500 hours during any consecutive 12 months of which 500 hours may be on ULSFO. Each combustion turbine shall not operate more than 17~~2~~ hours exclusively on ULSFO per calendar day~~.~~, or with a combination of ULSFO burning of 12 hours with 12 hours of natural gas for compliance with regional haze impact thresholds.
[Rule 62-210.200(PTE and BACT) F.A.C.; Rule 62-212.400(PSD), F.A.C. and Applicant Request]

8. Permitted Capacity: The nominal heat input rate to the combustion turbine is 1,806 MMBtu per hour when firing natural gas and 1,994 MMBtu per hour when firing 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. Authorized Fuels (Pre-onsite natural gas availability): Each combustion turbine shall fire ULSFO which shall contain no more than 0.0015% sulfur by weight as the primary fuel until ~~December 31, 2010 or when~~ natural gas is available at the facility.~~, whichever comes first~~.

   {Permitting Note: The applicant has indicated that the targeted date for completion of natural gas pipeline infrastructure and commencement of gas transportation service is approximately June 1, 2010.}

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

10. Authorized Fuels (Post-onsite natural gas availability): Each combustion 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 combustion turbine may fire ultra low sulfur fuel oil containing no more than 0.0015% sulfur by weight.
[Rules 62-210.200(PTE and BACT) and 62-212.400(PSD), F.A.C.]

11. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determinations and resulted in the emission standards specified in this permit. For any request to convert these units to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee shall submit a full PSD permit application complete with a new proposal of the Best Available Control Technology as if the units had never been built.
[Rules 62-212.400(12) and 62-212.400(BACT), F.A.C.]

EMISSIONS AND TESTING REQUIREMENTS

12. Emission Standards: Emissions from the combustion turbine shall not exceed the following standards.

Unit 1 and 2 Simple Cycle Combustion Turbines (EU 001 and 002)

Pollutant	Emission Standard[e]	Averaging Time	Compliance Method	Basis
NO_X[a] (Gas)	9.0 ppmvd @ 15% O_2	24-hr block, ~~30-day rolling average~~[f]	CEMS	BACT
	58.5 lb/hr	3 1-hr runs	Stack Test	
NO_X[a] (Oil)	42.0 ppmvd @ 15% O_2	24-hr block, ~~30-day rolling average~~[f]	CEMS	BACT
	329.4 lb/hr	3 1-hr runs	Stack Test	
NO_X (Gas)	15 ppmvd @ 15% O_2	4-hr rolling average[f]	CEMS	NSPS
NO_X (Oil)	42 ppmvd @ 15% O_2	4-hr rolling average[f]	CEMS	NSPS
CO[b] (Gas)	4.1 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	16.2 lb/hr	3 1-hr runs	Stack Test	
CO[b] (Oil)	8.0 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	38.2 lb/hr	3 1-hr runs	Stack Test	
PM/PM_{10}[c]	10 % Opacity	6-minute block	Visible Emissions Test	BACT
	2.0 gr S/100 SCF of gas/ 0.0015 % S fuel oil	N/A	Record Keeping	
SAM/SO_2[d]	2.0 gr S/100 SCF of gas/ 0.0015 % S fuel oil	N/A	Record Keeping	BACT

Comment [k1]: The 30-day rolling average is not applicable. NSPS Subpart KKKK requires a 4-hr rolling average.

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a. Continuous compliance with the 24-hr block NO_X standards shall be demonstrated based on data collected by the required Continuous Emissions Monitoring System (CEMS). The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments ~~shall~~ may also be used to demonstrate compliance with the individual standards for natural gas and ULSFO during the time of those tests. NO_X mass emission rates are at International Organization for Standardization (ISO) conditions and are defined as oxides of nitrogen expressed as NO_2.

Comment [k2]: Condition No. 15 indicates that CEMS RATA tests "may" substitute for annual compliance test.... This foot note uses "shall". It is requested that "may" be used instead of "shall" for consistency.

b. 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~~ may also be used to demonstrate compliance with the individual standards for natural gas and ULSFO. CO mass emission rates are at ISO conditions.

c. The sulfur fuel specification 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 specification effectively limits the potential emissions of SAM and SO_2 from the gas turbines and represents BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the

ASTM methods or a certified fuel sulfur analysis from the fuel vendor for determination of fuel sulfur as detailed in the draft permit.

e. 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 to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

f. 40 CFR 60, NSPS-Subpart KKKK as described in 60.4380(b)(1). Startup, shutdown and malfunction (SSM) emissions are to be included in the 4-hr rolling average calculations. Continuous compliance during SSM is not required by Subpart KKKK.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from the combustion turbines to: 340.2 tons/year of NO_X*, 67.7 tons/year of CO, 71 tons/year of* PM/PM_{10} *and 28.81 tons/year of* SO_2*. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs~~.~~}*

[Rules 62-4.070(3), 62-210.200 (BACT), 62-212.400(PSD), F.A.C. and 40 CFR 60, Subpart KKKK]

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

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

Method	Description of Method and Comments
7E	Determination of NOx Emissions from Stationary Sources (Instrumental)
9	Visual Determination of Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
20	Determination of NOx, SO_2, and Diluent Emissions from Stationary Combustion Turbines

The 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. [Rule 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

15. 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.]

~~15.~~16. Testing Requirements: Initial tests shall be conducted between 90% and 100% of permitted capacity, adjusted as appropriate, and at prevailing ambient conditions; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. Subsequent annual tests shall be conducted between 90% and 100% of permitted capacity adjusted as appropriate, and at prevailing ambient conditions in accordance with the requirements of Rule 62-297.310(2), F.A.C. Tests shall be conducted for each pollutant while firing each fuel in the CT. For each run during tests for visible emissions, emissions of CO recorded by the CEMS shall also be reported. Data collected from the reference method during the required CEMS quality assurance relative accuracy test audit (RATA) tests may substitute for annual compliance tests for NO_X and CO, provided the owner or operator indicates this intent in the submitted test protocol, and obtains approval prior to testing. If the RATA is conducted at less than permitted capacity, and the data is used for annual compliance, the requirements of 62-297.310(2) (Operating Rate During

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Testing) still apply. The mass emission rate standards are based on a turbine inlet condition of 59°F and 100 percent full load operation. Combustion turbine capacity and ~~M~~mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-297.310(2) and (7)(a), F.A.C.; and 40 CFR 60.8]

~~16.~~17. Initial Compliance Demonstration: Initial compliance stack tests while firing natural gas shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after the initial startup on natural gas. Initial testing on ULSFO shall be conducted within 60 days after achieving the maximum production rate on ULSFO, but not later than 180 days after the initial startup.~~of any fuel oil firing in the CT~~. In accordance with the test methods specified in this permit, the combustion turbine shall be tested to demonstrate initial compliance with the emission standards for NO_X, CO and with the visible emissions standard. ~~The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees~~. [Rules 62-4.070, 62-297.310(7)(a), F.A.C. and 40 CFR 60.8]
{Permitting Note: The applicant has indicated that the targeted date for completion of natural gas pipeline infrastructure and commencement of gas transportation service is June 1, 2010.}

~~17.~~18. Subsequent Compliance Testing: Annual compliance tests for NO_X, CO and visible emissions shall be conducted during each federal fiscal year (October 1st to September 30th). If normal operation on fuel oil is less than 400 hours per calendar year, then subsequent compliance testing on fuel oil is not required for that year. If normal operation on fuel oil exceeds 400 hours per year, the Department shall require compliance testing for NO_X, CO and visible emissions while firing fuel oil.
[Rules 62-4.070, 62-210.200(BACT) and 62-297.310(7)(a)4, F.A.C.]

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~~18.~~19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour block average CO emissions standards; and with the 24-hour block and ~~30 unit operating day~~4-hour rolling average NO_X emission standards based on data collected by the certified CEMS. Within 45 days of conducting any 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.
[Rules 62-4.070 and 62-210.200 (BACT), F.A.C.]

~~19.~~20. 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.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No 12 of this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

~~20.~~21. Definitions:

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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.

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

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.

{Permitting Note: The applicant has described startup of this unit as the period from 0 to just less than 50% load, and shutdown as the period beginning at just less than 50 % load to no load operation.}

[Rule 62-210.200(165, 242, and 258), F.A.C.]

~~21.~~22. 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.]

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~~22.~~23. Data Exclusion *Procedures for SIP Compliance*: *As per the procedures in this condition, limited* amounts of CEMS emissions data, as specified in conditions ~~23~~ 24 and 28 may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to, the duration of data excluded is minimized, and the procedures for data exclusion listed below are followed. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Limiting Data Exclusion:* If the compliance calculation using all valid CEMS emission data indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

b. *Event Driven Exclusion:* There must be an underlying event (startup, shutdown, malfunction, or fuel switching) in order to exclude data. If there is no underlying event, then no data may be excluded.

c. *Continuous Exclusion:* Data shall be excluded on a continuous basis for an underlying event. Data from discontinuous periods shall not be excluded for the same underlying event.

[Rule 62-210.700 F.A.C.]

~~23.~~24. Allowable Data Exclusions: The following data may be excluded from the corresponding SIP-based compliance demonstration for each of the events listed below in accordance with the Data Exclusion Procedures of condition 22:

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a. *Startup:* Up to 30 minutes of CEMS data may be excluded for each combustion turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup may be excluded.

b. *Shutdown:* Up to 30 minutes of CEMS data may be excluded for each combustion turbine shutdown. For shutdowns of less than 30 minutes in duration, only those minutes attributable to shutdown may be excluded.

c. *Malfunction*: Up to two hours (in any operating day) of CEMS data may be excluded due to a documented malfunction. 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 email.

d. *DLN Tuning*: CEMS data collected during initial or other major DLN tuning sessions may be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications or determined best practices. 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 one (1) day that details the

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activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design and Rule 62-4.070(3), F.A.C.]

~~d.~~e. *Fuel Switching*: Up to 60 minutes of CEMS data may be excluded for each fuel switch. For fuel switches of less than 60 minutes in duration, only those minutes attributable to fuel switching may be excluded.

All valid emissions data (including data collected during startup, shutdown, malfunction, DLN tuning, and fuel switching) shall be used to report emissions for the Annual Operating Report.

[Rules 62-210.200(BACT), 62-210.370 and 62-210.700, F.A.C.]

~~24.~~25. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. The notice may be by telephone, facsimile transmittal, or electronic mail. [Rule 62-4.070, F.A.C.]

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CONTINUOUS MONITORING REQUIREMENTS

~~25.~~26. CEM Systems: Subject to the following, the permittee shall install, calibrate, operate, and maintain a continuous emission monitoring system (CEMS) to measure and record the emissions of NO_X and CO from the combustion turbine in terms of the applicable standards. The monitoring system shall be installed, and functioning within the required performance specifications by the time of the initial compliance demonstration.

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a. *NO_X Monitor:* Each NO_X monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

b. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. 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.

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.

[Rules 62-4.070(3), 62-210.200(BACT), F.A.C. and 40 CFR Part 60, 40 CFR~~Subp~~ Part 75]

~~26.~~27. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C]

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~~27.~~28. CEMS Data Requirements for BACT Standards:

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, 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 emissions rates shall be corrected to ISO conditions.

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. 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.]

d. *~~30-unit operating day~~4-hour Rolling Average:* Compliance with this rolling average is as described in 40 CFR 60.4380(b)(1). Startup, shutdown and malfunction (SSM) emissions are to be included in the 4-hr rolling average calculations. Continuous compliance during SSM is not required by Subpart KKKK.

~~d.~~e. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction and DLN major 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. ~~22~~ 23 and ~~23~~ 24 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, DLN major 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.~~f. *Availability*: Monitor availability for the CEMS shall be based on performance standards, as set forth in 40 CFR Part 75.~~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~~

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~~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.]

CEMS REQUIREMENTS FOR ANNUAL EMISSIONS

~~28.~~29. CEMS Annual Emissions Requirement: The owner or operator shall use data from the NO_X and CO CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit. [Rules 62-210.200 and 62-210.370(3), F.A.C.]

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REPORTING AND RECORD KEEPING REQUIREMENTS

~~29.~~30. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the combustion turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, DLN tuning, and fuel switching). Such monitoring shall be made 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 62-210.200(BACT), F.A.C.]

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~~30.~~31. Monthly Operations Summary: By the 15th calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the combustion turbine for the previous month of operation: fuel consumption, hours of operation on each fuel, and the updated calendar year 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 62-210.200(BACT), F.A.C.]

~~31.~~32. 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 Sulfur Limit*: 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. *Distillate Fuel Oil Sulfur Limit*: 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 each 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 the 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.]

~~32.~~33. 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 D of this permit. [Rule 62-297.310(8), F.A.C.]

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~~33.~~34. 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 NO_X emissions in excess of the BACT permit standard following the NSPS format in 40 CFR 60.7(c), Subpart A. A summary of data excluded from SIP compliance calculations should also be provided. In addition, the report shall summarize the NO_X CEMS system monitor availability for the previous quarter.

c. *NSPS Reporting*: Within 30 days following the calendar ~~quarter~~semi-annual period, the permittee shall submit the written reports required by 40 CFR 60 Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) for the previous semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart 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) and 62-212.400(BACT), F.A.C. and 40 CFR 60.7 and 60.4375]

~~34.~~35. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with 62-210.370. Annual operating reports shall be submitted to the Compliance Authority as required by ~~by March 1st of each year. [~~ Rule 62-210.370(2), F.A.C.~~]~~

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TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

JEA

Greenland Energy Center

Units 1 and 2 Simple Cycle Combustion Turbines

Jacksonville, Duval County

DEP File No. 0310561-001-AC (PSD-FL-401)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation – New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

August 20, 2008

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

I. APPLICATION INFORMATION

A. APPLICANT

JEA - Greenland Energy Center (GEC)
21 West Church Street
Jacksonville, Florida 32202

Authorized Representative

James M. Chansler, P.E., D.P.A., Chief Operating Officer
JEA
21 West Church Street
Jacksonville, Florida 32202

B. PROCESSING SCHEDULE

- Application for Air Construction Permit received on April 21, 2008.
- Department's Request for Additional Information dated May 20, 2008.
- Applicant's Response to Request for Additional Information Received June 16, 2008.
- Department's Request for Additional Information e-mailed on June 30, 2008.
- Applicant's Response to Request for Additional Information Received July 11, 2008. Application complete.
- Department's Intent to Issue and Public Notice Package dated August 20, 2008.

C. FACILITY LOCATION

The Greenland Energy Center will be located at 12121 Phillips Highway in Jacksonville, Duval County. The site is 193 km from the Chassahowitzka National Wildlife Refuge; 78 km from Okeefenokee Wilderness (OW); and 128 km from Wolf Island Wilderness (WIW) all Federal Prevention of Significant Deterioration (PSD) Class I Areas.

The UTM coordinates for this site are Zone 450.218 km East and 3336.391 km North. The locations of Jacksonville and GEC are shown in the following figures.

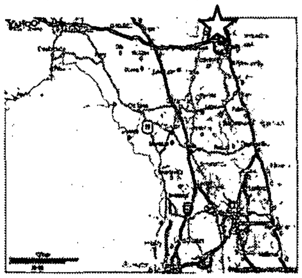


Figure 1. Location of Jacksonville

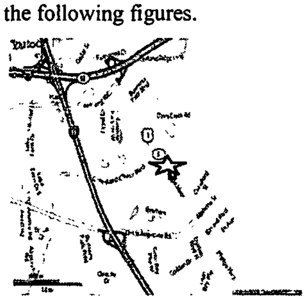


Figure 2. GEC Location

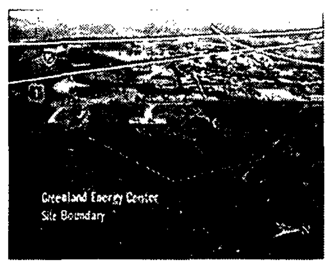


Figure 3. Site Aerial Photograph

D. PROPOSED FACILITY DESCRIPTION

The proposed facility is a new electric-generating facility referred to as Greenfield Energy Center (GEC). GEC will be built in two phases. The initial phase will be the construction of two natural gas-fired simple cycle combustion turbine (CT) units that are proposed to be operational June 2010. The second phase will convert these simple cycle units to a combined cycle combustion turbine ("2-on 1" configuration). Heat recovery equipment will be installed on the two simple cycle combustion turbines to capture enough heat energy to run a steam turbine (ST). This second phase is proposed to be operational in June 2012.

This technical evaluation and preliminary determination (TEPD) will consider only phase one.

The pictures below are the artist renderings of GEC at completion of phase one (simple cycle). During the phase one the generating station will produce a nominal plant output of 352 megawatt (MW) on natural gas and 380 MW on ultra low sulfur fuel oil (ULSFO).

Figure 4. North Northeast View

Figure 4A. Northeast View

The pictures below are the artist renderings of GEC at completion of phase two (combined cycle). During this phase the generating station will produce a nominal plant output of ~~570~~ 547 MW.

Figure 5. North Northeast View

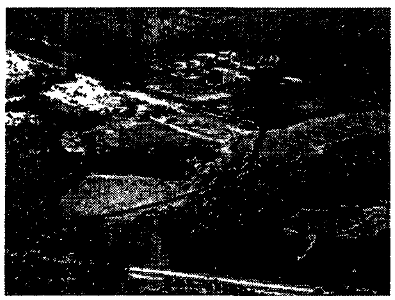


Figure 5A. Northeast View

E. PROJECT DESCRIPTION AS PROPOSED BY APPLICANT

Under phase one, the regulated emissions units at the new Greenland Energy Center site will include two General Electric (GE) 7FA simple cycle combustion turbine-electric generators (CT Units 1 and 2, Emissions Unit (EU) Nos. 001and 002) with a power output each of 190 MW while firing ULSFO and 176 MW while firing natural gas. Each CT will include the following major features:

- Dual Fuel Firing using natural gas (vaporized liquefied natural gas) or ULSFO with 0.0015 percent sulfur or 15 parts per million (ppm) sulfur.
- Dry low-NO_X (DLN) combustors for nitrogen oxides (NOx) reduction when firing natural gas and water injection while firing ULSFO.
- Static inlet air filtration.
- Mark VI control system.

The facility also includes two 115 foot stacks, one 350 brake horsepower (bhp) emergency diesel fire pump, one 1,500 kilowatt (kW) emergency diesel engine generator, one 5.84 million British thermal units per hour (MMBtu/hr) fuel gas heater and two 1.875 million gallons ULSFO storage tanks. Additionally, it includes a 2,500 gallon and a 500 gallon ULSFO day tanks for the 1,500 kW emergency engine generator and the 350 bhp emergency diesel fire pump, respectively.

This project will comprise the construction and installation of the following new regulated Air Resource Management System (ARMS) emission units:

EU ID	Emission Unit Description
001	Unit 1 – General Electric PG7241 FA gas turbine electrical generator (nominal 190 MW)
002	Unit 2 – General Electric PG7241 FA gas turbine electrical generator (nominal 190 MW)

This project will also authorize the construction of the following emission units which will be exempt from construction permitting requirements but certain new source performance standards may still apply. These emission units will be included in the Title V Operating Permit:

EU ID	Emission Unit Description
003	Two 1.875 Million gallon, One 2,500 gallon and one 500 gallon ULSFO Storage Tanks
004	1,500 kW Emergency Diesel Engine Generator and 350 bhp Emergency Diesel Fire Pump
005	5.84 MMBtu/hr Natural Gas Fired Fuel Gas Heater

The basis for exemption from construction permitting requirements is as follows:

1. Two 1.875 Million Gallon ULSFO Storage Tanks, One 2,500 Gallon and one 500 Gallon ULSFO Day Tanks (EU 003).

   Each of the ULSFO storage tanks and day tanks are generically exempt from the permitting requirements of Chapter 62-212, Florida Administrative Code (F.A.C.) because it satisfies the applicable criteria of paragraph 62-210.300(3)(b)1, F.A.C.

2. 1,500 kW Emergency Diesel Engine Generator and 350 bhp Emergency Diesel Fire Pump (EU 004)

   The emergency diesel engine generator along with the emergency diesel fire pump will combust no more than 32,000 gallons per year of diesel. These emission units are categorically exempt in accordance with Rules 62-210.300(3)(a)35 and 62-210.300(3)(a)36, F.A.C. respectively. The emergency diesel engine generator and the emergency diesel fire pump are subject to the manufacturer's certification requirements of compliance under 40 Code of Federal Regulations (CFR) Part 60, Subpart IIII.

3. 5.84 MMBtu/hr natural gas fired fuel gas heater (EU 005)

   The fuel gas heater is categorically exempt in accordance with Rule 62-210.300(3)(a)33, F.A.C.

The facility's Standard Industrial Classification Codes are listed in the following Table:

Table 1. Greenland Energy Center Project SIC Codes

STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)		
Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

Additional project details, as proposed, are described below:

Fuel: Two operating scenarios are proposed that correspond to the availability of natural gas fuel onsite. Under the first scenario (Scenario 1 – Pre-Onsite Natural Gas Availability), natural gas is not available and the CT will burn ULSFO (0.0015% sulfur by weight) exclusively. The applicant requests the operation to be limited to combined ULSFO usage of 30,213 thousand gallons per year (kgal/yr), equivalent to 1,000 hours of full load ULSFO firing per year per CT. When the natural gas pipeline construction is complete (Scenario 2 – Post Onsite Natural Gas Availability) and natural gas fuel is available onsite (expected by June 1, 2010), JEA proposes to fire each CT for 3,500 hours per year with up to~~on natural gas or 3,000 hours per year on natural gas and~~ 500 hours per year of that total on ULSFO (0.0015% sulfur by weight) and the balance on natural gas.

Controls: NO_X emission will be reduced with DLN combustion technology while firing natural gas, and water injection while firing fuel oil. Advanced burner design with good combustion practices will be used to minimize incomplete combustion of carbon monoxide (CO), particulate matter less than 10 microns (PM_{10}), and volatile organic compound (VOC). The use of natural gas and restricted operation on fuel oil will minimize emissions of sulfur dioxide (SO_2) and sulfuric acid mist (SAM).

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. The applicant will also install a continuous emissions monitor for demonstration of continuous compliance with permitted CO emissions.

Stack parameters: Unit 1 and 2 will each have a stack that is 115 feet tall with an approximate exit diameter of 20 feet. The following table summarizes the exhaust characteristics of the unit. Values given are approximate for operation at 59 degrees Fahrenheit (°F) at 100% load and a relative humidity of 60 percent. At 59 °F, the nominal capacity is approximately 176 MW when firing natural gas whereas the capacity is 190 MW when firing ULSFO.

Table 2. Approximate Exhaust Characteristics of Unit 1 and 2 at 100% Load and 59° F

Fuel	Total Heat Input (HHV)[1]	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Flow ACFM[2] @ 15% O_2
Gas	1806 mmBtu/hr	59° F	1,111 °F	2,428,785
Oil	1994 mmBtu/hr	59° F	1,094 °F	2,257,700

1 – higher heating value (HHV)
2 – actual cubic feet per minute (ACFM)

The key components of the GE 7FA CT are shown in the "quarter section" internal diagram of Figure 6.

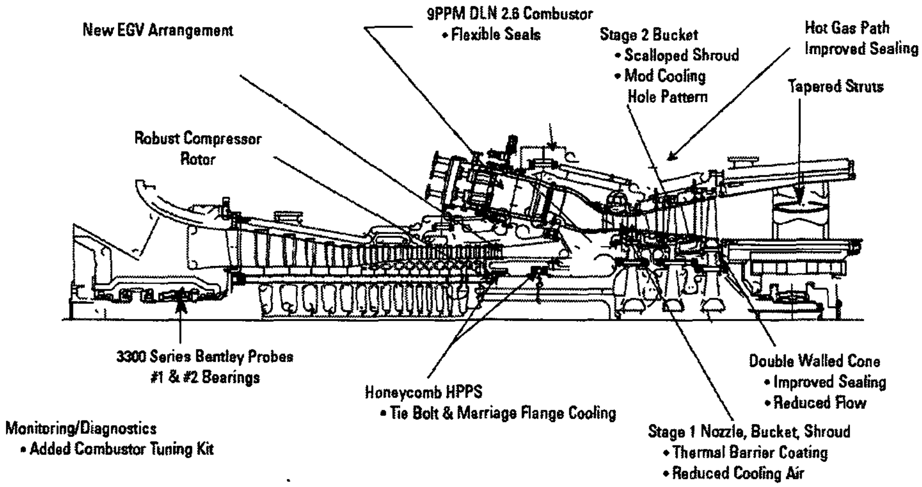


Figure 6. Quarter Section of GE 7FA (top)

F. Process Description

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 6) where it is compressed by a pressure ratio of about 15.5 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.

In general, flame temperatures in a typical combustor section can reach 3600° F. Units such as the GE 7FA operate at lower <u>flame</u> 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 initial phase of the GEC project, the unit will operate in simple cycle mode only, meaning that the gas turbine drives an electric generator while the exhausted gases are directed through the stack with no additional heat recovery. In the second phase, JEA ultimately plans to convert the simple cycle units to combined cycle combustion turbines.

II. RULE APPLICABILITY

A. Regulatory Categories

Title I, Part C, Clean Air Act (CAA): The facility will be located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility does not fall into one of the 28 Prevention of Significant Deterioration (PSD) Major Facility Categories with the lower PSD applicability threshold of 100 tons per year (TPY); therefore the 250 TPY threshold is applicable. Potential emissions of at least one regulated pollutant exceed 250 TPY, therefore the facility is classified as a "Major Stationary Source" of air pollution with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration of Air Quality.

Title I, Section 111, CAA: These units (EU 001 and 002; CT1 and CT2) will be subject to 40 CFR Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005).

Title I, Section 111, CAA: EU 004 (Emergency Diesel Engine and Emergency Diesel Fire Pump) will be subject to the manufacturer's certification requirements of compliance under 40 CFR 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines).

Title I, Section 111, CAA: EU 003 (ULSFO Storage Tanks) will not be subject to 40 CFR 60, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels). Since the vapor pressure of ULSFO is less than 3.5 kilopascal, the two ULSFO storage tanks are not subject to 40 CFR Part 60 subpart Kb.

Title I, Section 112, CAA: The facility will not be a "Major Source" of hazardous air pollutants (HAPs). EU 001 and 002 will not be subject to 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines). This standard is only applicable to emission units at a facility that is a major source of HAPs.

Title IV, CAA: The units (EU 001 and 002; CT1 and CT2) will be subject to the Acid Rain provisions of the Clean Air Act.

Title V, CAA: The facility will be 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 CO, NO_X, particulate matter/particulate matter less than 10 microns (PM/PM_{10}), SO_2, and VOC.

B. 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
62-204	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

C. 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	Standards of Performance for New Stationary Sources (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.

D. PSD PRECONSTRUCTION REVIEW REQUIREMENTS

The Department regulates major air pollution sources in accordance with Florida's PSD program, as described 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; or
- 5 tons per year of lead.

For new PSD-major facilities and modifications to existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SER) identified in Rule 62-210.200, F.A.C. Each pollutant exceeding the respective SER is considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions, and evaluate the air quality impacts. Although a facility may be considered a "major stationary source" with respect to PSD because of only one regulated pollutant, it is required to implement BACT for each "PSD-significant" pollutant. In accordance with Rule 62-212.400(4), F.A.C., for the construction of any new "major stationary source" or the major "modification" of any existing major stationary source, the applicant must provide the following information:

(a) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design and plant layout;

(b) A detailed schedule for construction of the source or modification;

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

(d) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact and an analysis of "good engineering practice" stack height; and

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

"Best Available Control Technology" or "BACT" as defined in Rule 62-210.200, F.A.C. is as follows:

(a) 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:

1. Energy, environmental and economic impacts, and other costs,

2. All scientific, engineering, and technical material and other information available to the Department; and

3. The emission limiting standards or BACT determinations of Florida and any other state;

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.*

(b) *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.*

(c) *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

(d) *In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.*

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]

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 – AQRV); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

E. PSD APPLICABILITY FOR THE PROJECT

The project is located in Duval County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The facility in the initial phase will consist of simple cycle CT, and therefore will not be on the list of 28 PSD major facilities categories. The facility will still be a major stationary source, as it has the potential to emit 250 TPY or more of at least one PSD pollutant. The applicant has also indicated the simple cycle units will be converted to combined cycle operation at a future date. As a combined cycle fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input, it is one of the 28 listed PSD major facility categories, and will have the potential to emit 100 TPY or more of at least one PSD pollutant. Therefore, the facility is a major stationary source and the project is subject to a PSD applicability review. The power block of the possible future combined cycle operations is expected to consist of a 2 x 1 combined cycle configuration which includes two combustion turbine generators (the currently proposed simple cycle units), two heat recovery steam generators (HRSG), and one steam turbine generator (STG). This configuration would produce a nominal plant output of approximately ~~570~~ 547 MW. The HRSG would also be equipped with duct burners that generate additional heat input to increase the steam generating capacity of the HRSG. Each CT/HRSG would have a single exhaust stack and a simple cycle by-pass stack. Since conceptual engineering on the combined cycle generation has not been completed, potential emissions from the combined cycle facility are preliminary in nature. It is expected that the combined cycle units would operate primarily on natural gas, with up to 500 hours per year per unit on ULSFO as a back-up.

The following table identifies the estimated emissions increases based on the initial application for the proposed initial simple cycle operation and the future combined cycle operation. The Department informed JEA that the new source review applicability for the simple cycle project was to be based on the potential emissions of the combined cycle conversion project. The BACT analysis was done only for the simple cycle project and a future BACT analysis will be conducted for the combined cycle conversion project when a new application is submitted for the second phase.

Table 3 - Summary of the Applicant's PSD Applicability

Pollutant	Simple Cycle Net Emissions Increase*(a)* (TPY)	Combined Cycle Net Emissions Increase*(b)* (TPY)	PSD Significant Emissions Rate (TPY)	Subject to PSD Review?*(c)*
CO	70.24	251.89	100	Yes
NOx	346.51	142.58	40	Yes
PM	71.25	215.41	25	Yes
PM_{10}	71.25	215.41	15	Yes
SAM	11.05	43.49	7	Yes
SO_2	28.82	72.65	40	Yes
VOC	13.0	34.40	40	No

Notes:

(a) The potential to emit (PTE) is the expected emissions from combustion turbine operation at 3,000 hours per CT per year on natural gas and 500 hours per CT per year on ULSFO. PTE from emergency equipments (EU 004) are included based on a combined fuel usage of not more than 32,000 gallons per year. PTE from fuel gas heater (EU 005) are included based on the unit firing natural gas for 8,760 hours per year.

(b)PTE based on firing 8,260 hours per year on natural gas with 500 hours per year on ULSFO, at International Organization for Standardization (ISO) conditions. NOx emissions in combined cycle mode controlled by a selective catalytic reduction (SCR) system, and good combustion controls for other pollutants (however, a detailed BACT analysis will be performed in the future application for combined cycle operation).

(c)PSD review for the simple cycle project is based on the expected PTE of the future combined cycle operation.

As shown in the table, the project is subject to PSD preconstruction review for emissions of: NOx, CO, SO_2, PM/PM_{10}, and SAM.

III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

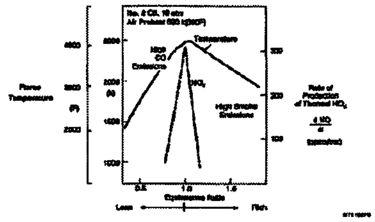
BACT Analysis for the Simple Cycle Combustion Turbines

A. NITROGEN OXIDES (NO_X)

1. Discussion of NO_X 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. 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 GE 7FA combustion turbine.[2]

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 known 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 7 below.



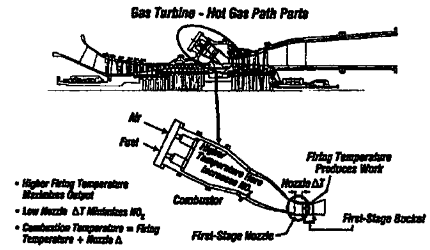


Figure 7. NO_X vs. Temperature, Equivalence Ratio.[3] Figure 8. Hot Gas Path Parts, NO_X Control

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 8, which is from a General Electric discussion on these principles.

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

For the purpose of further discussion, concentrations expressed in terms of ppmvd presume correction to 15% O_2 unless otherwise noted.

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. 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.

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. During dry low-NO_X combustion while gas firing, wet injection is not employed.

Dry Low-NO_X/CO (DLN) Combustion. 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. This principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in the following figure.

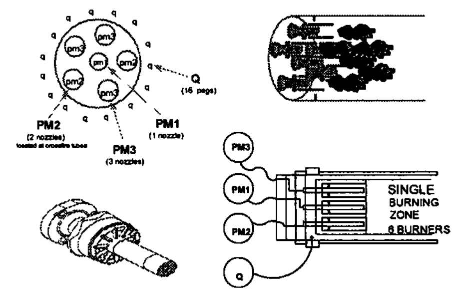
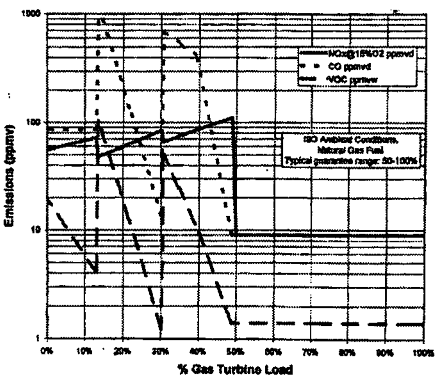


Figure 9. DLN-2.6 Fuel Nozzle Arrangement

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 Figure 10 below for a unit tuned to meet a limit of 9 ppmvd. The values for CO are "uncorrected" for oxygen (O_2). Values for VOC are uncorrected, "wet basis", and do not include methane and ethane because they are not defined as VOC.

The combustor design is such that NO_X concentrations equal 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.



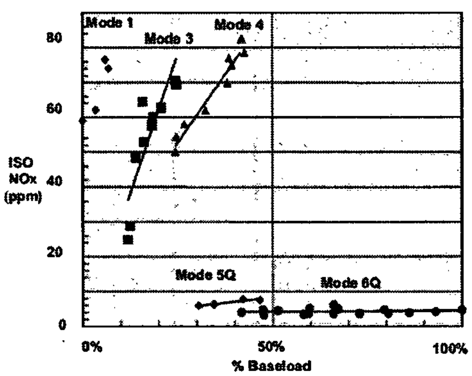


Figure 10. Design Emission Characteristics for DLN-2.6. **Figure 11. NO_X Performance of DLN-2.6**

Figure 11 is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility. Actual NO_X emissions are less than the design values. The Department has reviewed numerous reports and low load operation data from GE 7FA CT in Florida and can confirm the accuracy of the graph on the right. Also, actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

Table 4 summarizes the results of the new and clean tests conducted on a dual-fuel GE 7FA CT with DLN 2.6 combustors operating in simple cycle mode and burning natural gas at the existing Tampa Electric Polk Power Station.[4] The test results confirm that NO_X, CO, and VOC emissions are less than the design characteristics published by GE and given on the left hand side of the figure 10 above.

Table 4. Actual Performance of DLN-2.6 Combustors at Tampa Electric Polk Power Station

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

Numerous simple cycle GE 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 if assumed to equal 200 ppmvd.

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

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[6] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[7] By now, at least five such units are operating or under construction with emission limit 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.[8] 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 GEC Unit 1 and Unit 2.

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:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to approximately 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 combined cycle 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.
- TEC 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.

More recently, DEP issued permits for the West County Units 1 and 2, Treasure Coast Energy Center Unit 1 and FP&L Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil. The Department also required SCR on two recently constructed GE LM6000 simple cycle units at the City of Tallahassee's Hopkins facility.

SCR is a commercially available, demonstrated control technology currently employed on numerous combustion turbine projects permitted with very low NO_X emissions.

EMx™ formerly SCONO$_X$™. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was 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.

EMx™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[9] None was installed at a large facility.

EMx™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. EMx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. EMx™ systems also oxidize emissions of CO and VOC for additional emission reductions. EMx™ 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 5 contains averaged cost values for SCR with oxidation catalyst (SCR/CO) and for $SCONO_X^{TM}$ (now EMx^{TM}) developed by the applicant. The table presents the capital costs and annual operation and maintenance (O&M) costs for installing an SCR/oxidation catalyst and $SCONOx^{TM}$ system on each CT during natural gas and ULSFO firing scenario to achieve a NOx outlet emission level of 2.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd while firing gas, and a NOx outlet emission level of 8.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd when firing ULSFO.

Table 5. Cost Comparison between SCR and $SCONO_X^{TM}$ (now EMx^{TM})

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X^{TM}$	SCR/CO	$SCONO_X^{TM}$
7,023,000	28,474,000	2,169,000	6,947,000

Cost figures show that the SCR/oxidation catalyst package costs less than the EMx^{TM} system. While the Department does not accept or reject the values given in Table 5, it appears that EMx^{TM} is not cost-effective for the present project.

3. Applicant's NO_X BACT Proposal

The applicant eliminated several NO_X control strategies (including $XONON^{TM}$, Selective Non-Catalytic Reduction, EMx^{TM} (formerly $SCONOx^{TM}$), and hot SCR based on technical infeasibility, cost-effectiveness or unavailability for the size of CT under review. Therefore, the submitted BACT analysis was limited to DLN combustors for natural gas firing, wet injection for oil firing, and SCR with dilution air system as an add-on control.

The applicant estimated the installed capital cost of a SCR with dilution air system on each CT to be $5,058,000 and the total annualized cost to be $1,621,000 per year to further reduce emissions from 9/42 ppmvd (gas/oil) to 2/8 ppmvd (gas/oil) when firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year. This yields an overall reduction in NO_X emissions of 135 tons per year. The cost effectiveness for an SCR system for each CT was estimated to be $12,015 per ton of NO_X removed. The applicant concluded that the use of SCR on Units 1 and 2 is not cost effective.

The applicant proposed BACT limits of 9.0 ppmvd while firing natural gas and 42.0 ppmvd while firing fuel oil, based on the use of dry low-NO_X combustors and water injection for natural gas and fuel oil firing respectively.

4. Department's Review and Draft NO_X BACT Determination

SCR Considerations:

California has one of the most stringent New Source Review programs in the country. The current BACT level for NO_X emissions from natural gas-fired electrical generation turbines is ≤2.0 and ≤3.0 ppmvd for cogeneration/combined-cycle and simple-cycle power plants, respectively.[10]

The definition of BACT in California is closer to the Lowest Achievable Emissions Rate (LAER) definition that applies in most states under Non-attainment New Source Review. Nevertheless, LAER (in this case California BACT) is typically considered to be the "top" control in BACT reviews.

The Department considers 3 ppmvd NO_X as the "top" control and it is achievable by SCR. A permit recently issued to the City of Tallahassee for two simple cycle units includes BACT limits of 5 ppmvd achievable by SCR for NO_X.

The previously mentioned Tallahassee Hopkins project allows more frequent operation (up to 5,840 hours per CT per year) than the proposed unit which will only operate up to 3,500 hours per CT per year. Also, the pre-control emissions are greater for the natural gas firing case (25 ppmvd) compared with the present case. As a result, the cost per ton of reducing emissions from 25 to 5 ppmvd for the Tallahassee units is less compared with emission reductions from 9 to 2.0 ppmvd for the present project.

The Department does not necessarily accept or reject the cost estimates but agrees that SCR is not cost-effective for the simple cycle project given that it will be operating only 3,500 hours per CT per year. The applicant will be converting to combine cycle mode under phase 2 of the project, at which time SCR will be cost-effective for the project.

BACT Determination:

Considering the above discussions, the Department has made the following determination for the control of NO_X emissions from proposed Units 1 and 2:

- NO_X emissions while firing natural gas shall be limited to 9.0 ppmvd as BACT achievable by natural gas firing and use of dry low-NO_X combustion.
- The continuous limits for NO_X shall be based on 24-hr rolling averages.

Incidental Back up Fuel Oil Limits:

Back-up fuel oil use shall be limited to 500 hours per year when natural gas is available at the facility and NO_X emissions shall be limited to 42.0 ppmvd (NSPS) achievable by injection of water into the combustors for flame cooling. Initially, when natural gas is not available at the facility, Units 1 and 2 shall be limited to a combined fuel oil usage of 30,213 kgal/year.

B. CARBON MONOXIDE (CO)

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 (Tables 4), GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at 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.

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 the 4 GE7FA units is shown in Table 6 below.

Table 6. 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

Turbine	Quarter	CO Max 24-hr Block (ppmvd)	CO Min 24-hr Block (ppmvd)	CO Quarterly Average (ppmvd)
1B		1.9	0	1.14
1C		1.2	0	0.74

CO and VOC emissions *should be* and *are* 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.[11] 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.

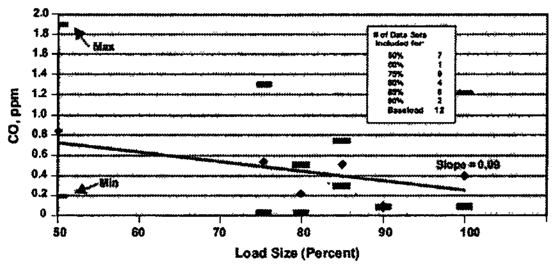


Figure 12. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

2. Low Load Considerations

Generally speaking, the full DLN features of the DLN 2.6 operate at loads greater than 50%. For that reason, some regulatory agencies disallow operation at less than 50% load in many 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.

The data in Figure 13 below suggest that there is some turndown capability while achieving low CO emissions. To maintain very low CO, the unit would need to operate in Modes 5Q or 6Q which means that five or all six fuel nozzles and quaternary pegs are in operation. 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.

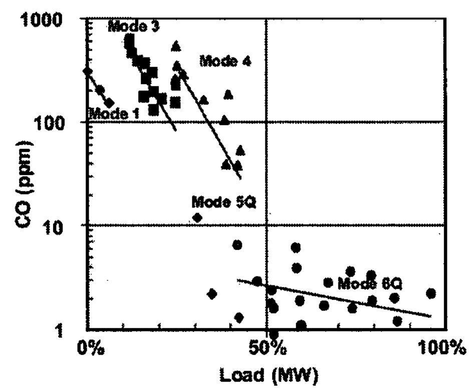


Figure 13. CO Emissions from DLN-2.6

The Department obtained data from operations at JEA Brandy Branch.[12] They are summarized in Table 7. For reference, a 65 MW load represents roughly 38% of full simple cycle CT 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.[13]

Table 7. 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

3. Applicant's CO BACT Proposal

JEA has proposed that the top CO control alternative when firing natural gas, good combustion controls, represents CO BACT for the GEC Unit 1 and Unit 2, corresponding to an emission limit of 4.1 ppmvd at 15 percent O_2 on a 24-hour block. The top CO control alternative when firing ULSFO, good combustion controls, represents CO BACT for the GEC Unit 1 and Unit 2, corresponding to an emission limit of 8.0 ppmvd at 15 percent O_2 on a 24-hour block.

The applicant provided information on CO control strategies, which can be classified into two categories: in-combustor CO formation control and post-combustion emission reduction. An in-combustor CO formation control process minimizes the quantity of CO formed in the combustion process. A post-combustion technology reduces the CO emissions in the flue gas stream after the CO has been formed in the combustion process. The different types of emission controls reviewed by the applicant for CO BACT analysis include:

- In-Combustor Type:
  - Dry low-NOx Burners.
- Post-Combustion Type:
  - Oxidation Catalyst.
  - SCONOx.

All three emission controls methods are considered technically feasible, but the application of SCONOx is currently limited to natural gas combined cycle combustion turbine units under 45 MW. In addition, SCONOx has not been previously installed and operated at a similar type and size of turbine. The cost information was provided in Table 5 and this control technology was considered to be not cost-effective for this project. Therefore, the submitted CO BACT analysis was limited to DLN combustors and Oxidation Catalyst system as an add-on control.

The applicant estimated the installed capital cost for the oxidation control system on each CT to be $1,965,000 and the total annualized cost to be $384,000 per year to further reduce emissions from 4.1/8 ppmvd (gas/oil) to 2.0 ppmvd (gas/oil) when firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year. This yields an overall reduction in CO emissions of 19.6 tons per year. The cost effectiveness for the oxidation catalyst system for each CT was estimated to be $19,592 per ton of CO removed. The applicant concluded that the use of oxidation catalyst system on Units 1 and 2 is not cost effective.

4. <u>Department's Review and Draft CO BACT Determinations</u>

Table 8 includes some recent BACT determinations for CO and PM in Florida and other states. JEA's <u>proposal</u> is included for comparison.

Some of the projects cited required oxidation catalyst. The "Top" emission <u>limit</u> 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.

It is clear from Tables 4, 6 and 7 that CO emissions from the GE 7FA are inherently low for the normal CT natural gas mode even without oxidation catalyst. CO emissions were consistently less than 5 ppmvd @15% O_2. Given the fact that emissions are actually very low, there would be little benefit in installing oxidation catalyst.

Table 8. CO and PM Standards for "F-Class" Combined Cycle Units

Comment [k1]: This table lists combined cycle units, but also lists JEA's GEC simple cycle units. Should the table show simple cycle BACT determinations instead?

Project Location	**CO – ppmvd (@15% O_2)**	**PM - lb/mmBtu (or gr/dscf or lb/hr)**
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	0.008
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)
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	20 lb/hr – (Front & Back) NH_3 = 5
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
JEA GEC Simple Cycle Units 1 & 2	**4.1 – NG** **8.0 – ULSFO**	**2 gr S/100 SCF of gas** **10% Opacity**
FMPA CIPP Unit 4	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – 24-hr (All Modes)	2 gr S/100 SCF of gas 10% Opacity NH3 = 5 ppmvd
OUC Stanton B, FL	4.1 – NG (DB off, Annual Test) 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)	2 gr S/100 SCF of gas 0.0015% sulfur fuel oil 10% Opacity NH_3 = 5 ppmvd
FPL Turkey Pt., FL	4.1 – NG (DB off, Annual Test) 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)	2 gr S/100 SCF of gas 0.0015% sulfur fuel oil 10% Opacity NH_3 = 5 ppmvd
FMPA TCEC, FL	4.1 – NG (DB off, Annual Test) 8.0 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	2 gr S/100 SCF of gas 0.0015% sulfur fuel oil 10% Opacity NH_3 = 5 ppmvd
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	0.011
Calpine OEC, PA	10 (1-hr)	0.0061
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5 ppmvd
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) NH_3 = 5 ppmvd

Notes: NG = Natural Gas; DB = Duct Burner; PA = Power Augmentation; FO = Fuel Oil; GE = General Electric; WH = Westinghouse; ABB = Asea Brown Bovari; gr/dscf = grains per dry standard cubic feet; NH_3 = Ammonia

The Department concurs with the JEA proposal for BACT given in Table 8. BACT for CO is determined to be the 4.1 ppmvd @ 15% O_2 for natural gas firing and 8.0 ppmvd @ 15% O_2 for ULSFO.

The BACT determination for CO is consistent with recent determinations for the FP&L West County (G-Class), FP&L Turkey Point Unit 5, Progress Energy Bartow Repowering, FMPA Treasure Coast project and the OUC Stanton Unit 4 project.

JEA estimates that the cost to reduce CO emissions from the levels in their BACT proposal to 2 ppmvd would be approximately $19,592 per ton of CO removed. While the Department does not necessarily accept or reject the JEA estimates, the Department concurs that the oxidation catalyst is not cost-effective for the JEA GEC Unit 1 and Unit 2 project. The Department believes very low CO emissions will be achieved at GEC Unit 1 and Unit 2 without oxidation catalyst and without requiring the applicant to obtain even lower emission guarantees from the suppliers.

C. 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 a refinery or gas conditioning plant prior to distribution to the market.

For this project the applicant has proposed as BACT the use of clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF). For reference, the sulfur specification of the natural gas is approximately equal to 0.006% (by weight). For ULSFO, the sulfur fuel specification is 0.0015% (by weight).

JEA estimated 29 TPY of SO_2 in the simple cycle mode and 73 TPY in the combined cycle mode (Phase II) and 11 TPY of SAM from GEC Unit 1 and Unit 2. Realistically, annual emissions will be approximately one-fourth of the estimated values because the sulfur concentration in the pipeline gas is typically closer to 0.5 gr/100 SCF than to 2 gr/100 SCF.

At such low sulfur concentrations, annual emissions of both pollutants will likely be less in the simple cycle mode than the respective PSD thresholds of 40 and 7 TPY of SO_2 and SAM respectively. The Department accepts JEA's BACT proposal for SO_2 and SAM. This approach is consistent with other recently permitted projects.

D. PARTICULATE MATTER (PM/PM_{10})

Particulate matter (PM/PM_{10}) is emitted from combustion turbines due to incomplete combustion of ash and sulfur present in the fuels. They are minimized by use of clean fuels, with low ash and sulfur contents, and good combustion practices. Clean fuels are a necessity in combustion turbines in order to avoid excessive maintenance due to damaged turbine blades and other components already exposed to very high temperatures and pressures.

The use of DLN combustor technology to maximize combustion efficiency, and the use of low ash, low sulfur fuels is proposed as BACT for PM/PM_{10}. The Department also recognizes that $PM_{2.5}$ is now a regulated pollutant. PM_{10} will be used as a surrogate for $PM_{2.5}$ as per EPA guidance. According to the applicant, *combustion efficiency is projected to be greater than 99 percent with the DLN technology.* Additionally, a visible emissions limit of 10 percent opacity has been proposed as a surrogate limit for PM/PM_{10}. The Department agrees with the applicant, and the draft BACT standard for PM/PM_{10} is the proposed fuel specification and opacity limit.

E. BACT Determinations for the Simple Cycle Combustion Turbines

The Department establishes the following standards as the Best Available Control Technology for the simple cycle combustion turbine Units 1 and 2 at the GEC Power Project.

Table 9. Draft BACT Determinations – Greenland Energy Power Project Units 1 and 2

Comment [k2]: Please refer to comments on this table located under Condition No. 12 of the PSD Permit.

Pollutant	Emission Standard[e]	Averaging Time	Compliance Method	Basis
NO_X[a] (Gas)	9.0 ppmvd @ 15% O_2	24-hr block~~, 30-day rolling average~~[f]	CEMS	BACT
	58.5 lb/hr	3 1-hr runs	Stack Test	
NO_X[a] (Oil)	42.0 ppmvd @ 15% O_2	24-hr block~~, 30-day rolling average~~[f]	CEMS	BACT
	329.4 lb/hr	3 1-hr runs	Stack Test	
CO[b] (Gas)	4.1 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	16.2 lb/hr	3 1-hr runs	Stack Test	
CO[b] (Oil)	8.0 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	38.2 lb/hr	3 1-hr runs	Stack Test	
PM/PM_{10}[c]	10 % Opacity	6-minute block	Visible Emissions Test	BACT
	2.0 gr S/100 SCF of gas/ 0.0015 % S fuel oil	N/A	Record Keeping	
SAM/SO_2[d]	2.0 gr S/100 SCF of gas/ 0.0015 % S fuel oil	N/A	Record Keeping	BACT

a. 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 KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas and ULSFO during the time of those tests. NO_X mass emission rates are at ISO conditions and are defined as oxides of nitrogen expressed as NO_2.

b. 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 and ULSFO. CO mass emission rates are at ISO conditions.

c. The sulfur fuel specification 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 specification effectively limits the potential emissions of SAM and SO_2 from the gas turbines and represents 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. *The mass emission rate standards are based on a turbine inlet condition of 59°F and using the higher heating value (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.*

~~f. 40 CFR 60, NSPS Subpart KKKK as described in 60.4380(b)(1).~~

Comment [k3]: This table shows BACT determinations. NSPS limits are not applicable.

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IV. NEW SOURCE PERFORMANCE STANDARDS

A. COMBUSTION TURBINES

New stationary gas turbines are subject to the federal New Source Performance Standards in Subpart KKKK of 40 CFR 60. This federal regulation establishes the following emission standards for new combustion turbines with a heat input at peak load of > 850 mmBtu/hr.

- NO_X (while firing natural gas) - 15 ppm @ 15 percent O_2 or 0.43 pounds per megawatt hour (lb/ MWh)
- NO_X (while firing fuels other than natural gas) - 42 ppm at 15 percent O_2 or 1.3 lb/MWh
- SO_2 - 0.90 lb/MWh gross output, or 0.060 lb SO_2/MMBtu heat input

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. Appendix G of the permit summarizes applicable federal requirements.

V. 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 NO_X emissions.

B. ALLOWABLE DATA EXCLUSIONS

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."

Operation of the General Electric Frame 7FA combustion turbine in lean premix mode is achieved at least by 50% of base load conditions. Simple cycle gas turbines are designed for quick startup and operate at high load levels. Operation of the large frame gas turbines is generally automated and malfunctions have been infrequent.

Dry low-NO_X 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 NO_X and CO emissions, and extends the life of the unit components. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short, and once tuned, the gas turbine emissions will be minimized. 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. Other minor tuning sessions are expected to occur periodically on an as needed basis between major tuning sessions.

Based on information from General Electric regarding startup and shutdown, and the information above regarding tuning, the Department establishes the following conditions for excess emissions for the combustion turbine for which a limited amount of data may be excluded from the NO_X continuous compliance determinations.

- 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 each startup, up to 30 consecutive minutes of excess emissions may be excluded from the continuous compliance determinations.
- For each shutdown, up to 30 consecutive minutes of excess emissions may be excluded from the continuous compliance determinations.
- No more than 2 hours of CEMS data in any 24-hour period shall be excluded from compliance demonstrations due to a malfunction.
- CEMS data collected during initial or other DLN tuning sessions may be excluded from the compliance demonstrations provided that tuning session is performed in accordance with the manufacturer's specifications. Prior to performing any tuning sessions, the permittee shall provide the Compliance Authority with an advance notice detailing the activity and proposed tuning schedule.

VI. AIR QUALITY IMPACT ANALYSIS

This section provides a general overview of the modeling analyses required for PSD preconstruction review followed by the specific analyses required for this project.

A. Overview of the Required Modeling Analyses

Pursuant to Rule 62-212.400, F.A.C., the applicant is required to conduct the following analyses for each PSD significant pollutant:

- A preconstruction ambient air quality analysis,
- A source impact analysis based on EPA-approved models, and
- An additional impact analysis.

For the purposes of any required analysis, NO_X emissions will be modeled as NO_2 and only PM_{10} emissions will be considered when modeling particulate matter.

Preconstruction Ambient Monitoring Analysis

Generally, the first step is to determine whether the Department will require preconstruction ambient air quality monitoring. Using an EPA-approved air quality model, the applicant must determine the predicted maximum ambient concentrations and compare the results with regulatory thresholds for preconstruction ambient monitoring, known as de minimis air quality levels. The regulations establish de minimis air quality levels for several PSD pollutants as shown in the following table. For ozone, there is no de minimis air quality level because it is not emitted directly. However, since NO_2 and VOC are considered precursors for ozone formation, the applicant may be required to perform an ambient impact analysis (including the gathering of ambient air quality data) for any net increase of 100 tons per year or more of NO_2 or VOC emissions.

If the predicted maximum ambient concentration is less than the corresponding de minimis air quality level, Rule 62-212.400(3)(e), F.A.C. exempts that pollutant from the preconstruction ambient monitoring analysis. If the predicted maximum ambient concentration is more than the corresponding de minimis air quality level (except for non-methane hydrocarbons), the applicant must provide an analysis of representative ambient air concentrations (pre-construction monitoring data) in the area of the project based on continuous air quality monitoring data for each such pollutant with an Ambient Air Quality Standard (AAQS). If no such standard exists, the analysis shall contain such air quality monitoring data as the Department determines is necessary to assess ambient air quality for that pollutant.

Table 10. Regulatory Thresholds for Preconstruction Ambient Monitoring

PSD Pollutant	De Minimis Air Quality Levels
Carbon monoxide (CO)	575 µg/m3, 8-hour average
Nitrogen dioxide (NO_2)	14 µg/m3, annual average;
Particulate Matter (PM_{10})	10 µg/m3, 24-hour average
Sulfur dioxide (SO_2)	13 µg/m3, 24-hour average
Lead (Pb)	0.1 µg/m3, 3-month average
Fluorides (Fl)	0.25 µg/m3, 24-hour average
Total reduced sulfur (TRS)	10 µg/m3, 1-hour average
Hydrogen sulfide (H_2S)	0.2 µg/m3, 1-hour average
Reduced sulfur compounds (RSC)	10 µg/m3, 1-hour average
Mercury (Hg)	0.25 µg/m3, 24-hour average

If preconstruction monitoring data is necessary, the Department may require the applicant to collect representative ambient monitoring data in specified locations prior to commencing construction on the project. Alternatively, the Department may allow the requirement for preconstruction monitoring data to be satisfied with data collected from the Department's extensive ambient monitoring network. Preconstruction monitoring data must meet the requirements of Appendix B of 40 CFR 58 during the operation of the monitoring stations. The preconstruction monitoring data will be used to determine the appropriate ambient background concentrations to support any required AAQS analysis.

Finally, after completing the project, the Department may require the applicant to conduct post-construction ambient monitoring to evaluate actual impacts from the project on air quality.

Source Impact Analysis

For each PSD-significant pollutant identified above, the applicant is required to conduct a source impact analysis for affected PSD Class I and Class II areas. This analysis is to determine if emissions from this project will significantly impact levels established for Class I and II areas. Class I areas include protected federal parks and national wilderness areas (NWA) that are under the protection of federal land managers. Table 11 identifies the Class I areas located in Florida or that are within 200 kilometers in nearby states. Class II areas represent all other areas in the vicinity of the facility open to public access that are not Class I areas.

Table 11. Class I Areas Within 200 km of Project

Class I Area	State	Federal Land Manger
Bradwell Bay NWA	Florida	U.S. Forest Service
Chassahowitzka NWA	Florida	U.S. Fish and Wildlife Service
Everglades National Park	Florida	National Park Service
Okefenokee NWA	Georgia	U.S. Fish and Wildlife Service
St. Marks NWA	Florida	U.S. Fish and Wildlife Service
Wolf Island NWA	Georgia	U.S. Fish and Wildlife Service

An initial significant impact analysis is conducted using the worst-case emissions scenario for each pollutant and corresponding averaging time. The regulations define separate significant impact levels for Class I and Class II areas for CO, NO_2, Pb, PM_{10} and SO_2. Based on the initial significant impact analysis, no additional modeling is required for any pollutant with a predicted ambient concentration less than the corresponding significant impact level. However, for any pollutant with a predicted ambient concentration exceeding the corresponding significant impact level, the applicant must conduct a full impact analysis. In addition to evaluating impacts caused by the project, a full impact modeling analysis also includes impacts from other nearby major sources (and any potentially-impacting minor sources within the radius of significant impact) as well to determine compliance with:

- The PSD increments and the federal air quality related values (AQRV) for Class I areas.
- The PSD increments and the AAQS for Class II areas.

As previously mentioned, for any net increase of 100 tons per year or more of VOC or NO_2 subject to PSD, the applicant may be required to perform an ambient impact analysis for ozone including the gathering of ambient ozone data.

PSD Class I Area Model

The California Puff (CALPUFF) dispersion model is used to evaluate the potential impacts on PSD Class I increments, the federal land manager's Air Quality Related Values (AQRV) for regional haze as well as nitrogen and sulfur deposition. The CALPUFF model 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. It is also 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 mechanisms.

The meteorological data used in the CALPUFF model is processed by the California Meteorological (CALMET) model. Data from multiple meteorological stations is processed by the CALMET model to produce a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties and surface characteristics are produced by the CALMET model as well.

PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model is used to evaluate short range impacts from the proposed project and other existing major sources. In November of 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 kilometers of a source. The AERMOD model is a replacement for the Industrial Source Complex Short-Term model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. The model can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods. In addition to the PSD Class II modeling, it is also used to model the predicted impacts for comparison with the de minimis ambient air quality levels when determining preconstruction monitoring requirements.

For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). 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 in each modeling scenario and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights.

Stack Height Considerations

GEP stack height means the greater of 65 meters (213 feet) or the maximum nearby building height plus 1.5 times the building height or width, whichever is less. Where the affected stacks did not meet the requirements for GEP stack height, building downwash was considered in the modeling analyses. Based on a review of this application, the Department determines that the project 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 if and when EPA revises 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.

Additional Impact Analysis

In addition to the above analyses, the applicant must provide an evaluation of impacts to: soils, vegetation, and wildlife; air quality related to general commercial, residential and industrial growth in the area that may result from the project; and regional haze in the affected Class I areas.

B. PSD Significant Pollutants for the Project

As discussed previously, the proposed project will increase emissions of the following pollutants in excess of the PSD significant emissions rates: CO, NO_X, PM_{10}, SO_2 and SAM. For the purposes of any required analysis, NOx emissions will be modeled as NO_2 and only PM_{10} emissions will be considered when modeling particulate matter. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM.

C. Preconstruction Ambient Monitoring Analysis

Using the AERMOD model, the applicant predicted the following maximum ambient impacts from the project.

Table 12. De Minimis Air Quality Levels

.Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	De Minimis Concentration ($\mu g/m^3$)	Greater than De Minimis?
CO	8-hr	17	575	NO
NO_2	Annual	0.73	14	NO
PM_{10}	24-hr	4.03	10	NO
SO_2	24-hr	0.22	13	NO

As shown above, CO, NO_2, PM_{10} and SO_2 are exempt from preconstruction monitoring because the predicted impacts are less than the de minimis levels. In addition, the project results in PSD net emissions increases of 347 tons/year of NO_2, which is above the threshold of 100 tons/year, which requires an ambient impact analysis including the gathering of ambient air quality data. However, the Department maintains an extensive quality-assured ambient monitoring network throughout the state. The following table summarizes ambient data from 2004 to 2006 available for existing nearby monitoring locations.

Table 13. Representative Ambient Concentrations

Pollutant	Averaging Time	Ambient Concentration	Monitor Location
NO_2	Annual	26.2	Jacksonville
Ozone	8-hour	74	Jacksonville

The existing monitoring data show no violations of any ambient air quality standards. The Department determines that the data collected from these monitors is representative of the air quality in the vicinity of the project and may be used to satisfy the preconstruction monitoring requirements for NO_2 and ozone. As necessary, the above ambient concentrations will be used as the ambient background concentrations for any required AAQS analysis.

The applicant and the Department discussed available options for potentially predicting ambient ozone impacts caused by the NO_2 emissions increases (ozone precursor pollutant) from the project. No stationary point source models are available or approved for use in predicting ozone impacts. Although regional models exist for predicting ambient ozone levels, it is unlikely that impacts caused by this project could be adequately evaluated because it is so small compared to regional effects. The Department determines that the use of a regional model incorporating the complex chemical mechanisms for predicting ozone formation is not appropriate for this project. No further modeling is required for ozone impacts.

D. Source Impact Analysis for PSD Class I Areas

Affected PSD Class I Areas

For PSD Class I areas within 200 kilometers of the facility, the table identifies each affected Class I area as well as the distance to the facility and the number of receptors used in the modeling analysis. Since each of these areas are greater than 50 kilometers from the proposed facility, long-range transport modeling was required for the PSD Class I impact assessment.

Table 14. Affected PSD Class I Modeling Identities

PSD Class I Area	Distance	Receptors
Chassahowitzka NWA	193	113
Okefenokee NWA	78	500
Wolf Island NWA	128	30

Meteorological Data for PSD Class I Analysis

Meteorological data from 2001 through 2003 for a 4-kilometer Florida domain were obtained and processed for use in the PSD Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the guidance from the federal land managers.

Results of PSD Class I Significant Impact Analysis

Using the CALPUFF model, the applicant predicted the following maximum ambient impacts from the project.

Table 15. Significant Impact Analysis for PSD Class I Areas

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m³)	Significant Impact Level (μg/m³)	Significant Impact?	Affected Class I Area
NO_2	Annual	0.003	0.1	NO	Okefenokee NWA
PM_{10}	Annual	0.001	0.2	NO	Okefenokee NWA
	24-hour	0.09	0.3	NO	Okefenokee NWA
SO_2	Annual	0.0003	0.08	NO	Okefenokee NWA
	24-hour	0.~~006~~02	0.2	NO	Okefenokee NWA
	3-hour	0.~~13~~04	1.0	NO	Okefenokee NWA

As shown, the maximum predicted impacts are less than the corresponding significant impact levels for each pollutant. Therefore, a full impact analysis for the PSD Class I areas is not required.

E. Source Impact Analysis for PSD Class II Areas

Meteorological Data for PSD Class II Analysis

Meteorological data used in the AERMOD model consisted of a concurrent five-year period of hourly surface weather observations and twice-daily upper air soundings from the Jacksonville International Airport. The five-year period of meteorological data was from 2001 through 2005. This station was selected for use in the evaluation because it is the closest primary weather station to the project area and is most representative of the project site.

For the preliminary significant impact analysis, the highest short-term predicted concentrations will be compared to the respective significant impact levels. Since five years of data are available, the highest-second-high (HSH) short-term predicted concentrations will be used for any required AAQS and PSD Class II increment analysis with regard to short-term averages. However, for annual averages, the highest predicted annual average will be compared with the corresponding annual level.

Results of the Significant Impact Analysis

The following table shows the results of the preliminary PSD Class II significant impact analysis.

Table 16. Significant Impact Analysis for PSD Class II Areas (Vicinity of Facility)

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?	Radius of Significant Impact (km)
CO	8-hr	17	500	NO	NONE
	1-hr	28	2,000	NO	NONE
NO_2	Annual	0.73	1	NO	NONE
PM_{10}	Annual	0.06	1	NO	NONE
	24-hr	4.03	5	NO	NONE
SO_2	Annual	0.01	1	NO	NONE
	24-hr	0.22	5	NO	NONE
	3-hour	0.62	25	NO	NONE

As shown above, the predicted impacts of CO, NO_2, PM_{10} and SO_2 are well below the corresponding PSD Class II significant impact levels and no further analysis is required.

F. Additional Impacts Analysis

Impacts on Soils, Vegetation and Wildlife

The maximum predicted ground-level concentrations of CO, NO_X, PM_{10} and SO_2 from the proposed project and all other nearby sources are below the corresponding AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils, vegetation or wildlife in the vicinity of the project.

Air Quality Impacts Related to Growth

The proposed modification will not significantly change employment, population, housing, commercial development, or industrial development in the area to the extent that a significant air quality impact will result.

Regional Haze Analysis

The applicant conducted an AQRV analysis for the Class I areas. No significant impacts on these areas are expected. A regional haze analysis using the long-range transport model CALPUFF was conducted for the PSD Class I areas. The regional haze analysis showed no significant impact on visibility in these areas with ULSFO fuel burning limited to 17 hours a day, or with a combination of ULSFO burning of 12 hours with 12 hours of natural gas. This restriction is necessary to limit the daily NOx emissions from the combustion turbines. This limit has been incorporated into the permit. Total nitrogen deposition rates on the PSD Class I areas were also predicted using CALPUFF. The maximum predicted nitrogen deposition rates are below the threshold levels recommended by the federal land manager.

G. Conclusion on Air Quality Impacts

As described in this report and based on the required ambient impact analyses, the Department has reasonable assurance that the proposed project will not cause, or significantly contribute to, a violation of any AAQS or PSD increment.

VII. CONCLUSION

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

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SECTION IV. APPENDICES

CONTENTS

SECTION IV. APPENDIX A

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

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

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

New Permit Numbers

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

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

"2222" represents the specific facility ID number for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

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

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

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

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

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

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

gr/dscf: grains per dry standard cubic feet

HAP: hazardous air pollutant

Hg: mercury

HHV: higher heating value

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

SECTION IV. APPENDIX B

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, F.S. 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), F.S., 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 F.S. 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 F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S.. 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 F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.

11. This permit is transferable only upon Department approval in accordance with 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 (applicable);
    b. Determination of Prevention of Significant Deterioration (applicable); and
    c. Compliance with New Source Performance Standards (applicable).

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.

COMMON CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the 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 as applicable under PSD Permit Condition no. 24. [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 permittee 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 (VOC) or organic solvents (OS) 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) and 62-210.200(Definitions), 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% opacity. This regulation does not impose a specific testing requirement. [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.]

{Permitting Note: Rule 62-210.700 (Excess Emissions), F.A.C., cannot vary any NSPS or NESHAP provision.}

RECORDS AND REPORTS

10. 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 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. 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 as required by~~by March 1st of each year. [~~ Rule 62-210.370(3), F.A.C.~~]~~

SECTION IV. APPENDIX D
COMMON TESTING REQUIREMENTS

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the facility.

COMPLIANCE TESTING REQUIREMENTS

1. 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.]

2. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. 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. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

3. 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.]

4. Applicable Test Procedures

   a. *Required Sampling Time.*

      (1) 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.

      (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

         (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

   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.

d. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

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

5. 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.]

6. 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. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

   (a) Did not operate; or

   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

   (a) Visible emissions, if there is an applicable standard;

   (b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

   (c) c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. 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.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *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.

c. *Waiver of Compliance Test Requirements.* If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.]

RECORDS AND REPORTS

8. Test Reports:

a. 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.

b. 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.

c. 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.]

SECTION IV. APPENDIX E

SUMMARY OF BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATIONS

The Department establishes the following standards as the Best Available Control Technology for the simple cycle combustion turbine Units 1 and 2 at the Greenland Energy Center Power Project.

Draft BACT Determinations – Greenland Energy Power Project Units 1 and 2

Comment [k1]: Please refer to comments on PSD permit Condition No. 12.

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
NO_X[a] (Gas)	9.0 ppmvd @ 15% O_2	24-hr block~~, 30-day rolling average~~[f]	CEMS	BACT
	58.5 lb/hr	3 1-hr runs	Stack Test	
NO_X[a] (Oil)	42.0 ppmvd @ 15% O_2	24-hr block~~, 30-day rolling average~~[f]	CEMS	BACT
	329.4 lb/hr	3 1-hr runs	Stack Test	
CO[b] (Gas)	4.1 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	16.2 lb/hr	3 1-hr runs	Stack Test	
CO[b] (Oil)	8.0 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	38.2 lb/hr	3 1-hr runs	Stack Test	
PM/PM_{10}[c]	10 % Opacity	6-minute block	Visible Emissions Test	BACT
	2.0 gr S/100 SCF of gas/ 0.0015 % S fuel oil	N/A	Record Keeping	
SAM/SO_2[d]	2.0 gr S/100 SCF of gas/ 0.0015 % S fuel oil	N/A	Record Keeping	BACT

a. 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 KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas and ULSFO during the time of those tests. NO_X mass emission rates are at ISO conditions and are defined as oxides of nitrogen expressed as NO_2.

b. 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 and ULSFO. CO mass emission rates are at ISO conditions.

c. The sulfur fuel specification 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 specification effectively limits the potential emissions of SAM and SO_2 from the gas turbines and represents 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. 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 to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

~~f. 40 CFR 60, NSPS Subpart KKKK as described in 60.4380(b)(1).~~

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SECTION IV. APPENDIX F

NSPS SUBPART A, 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.

NSPS SUBPART KKKK REQUIREMENTS FOR STATIONARY COMBUSTION TURBINES

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NOx) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NOx emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOx) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOx)?

(a) You must meet the emission limits for NOx specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOx.

§ 60.4325 What emission limits must I meet for NOx if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NOx emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. 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 related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOx if I use water or steam injection?

(a) If you are using water or steam injection to control NOx emissions, you must 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 when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOx formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode.

(iii) For any turbine that uses SCR to reduce NOx emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOx emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NOx CEMS is chosen:

(a) Each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent 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 with each monitor 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 for each monitor to validate the NOx emission rate for the hour.

(c) Each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOx concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NOx diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NOx emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NOx emission rate, in lb/MWh, (NOx)h = hourly NOx emission rate, in lb/MMBtu, (HI)h = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)t = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 106 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad \text{(Eq. 4)}$$

Where:

E = NOx emission rate in lb/MWh,

(NOx)m = NOx emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You 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. You must develop and keep onsite a parameter monitoring plan which explains the procedures used to document proper operation of the NOx emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NOx emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NOx emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping onsite (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in§60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. 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.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *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).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) 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 (c)(1) and (c)(2) 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 §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) 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 (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, 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 greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) 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:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) 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 half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NOx?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling 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 §60.4320, 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 when a fuel is being burned that requires water or steam injection for NOx control will also be considered an excess emission.

(2) A period of monitor downtime is 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.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOx emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4- hour rolling average NOx emission rate" is the arithmetic average of the average NOx emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOx emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOx emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NOx emission rate" is the arithmetic average of all hourly NOx emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOx emissions rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NOx emission controls:

(1) An excess emission is 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.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) 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 combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must 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 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) 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 ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NOx limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NOx limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOx?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NOx concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NOX emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \quad \text{(Eq. 5)}$$

Where:

E = NOx emission rate, in lb/MWh

1.194 × 10−7 = conversion constant, in lb/dscf-ppm

(NOx)c = average NOx concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NOX and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flow meter (or flow meters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOx emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NOx emission rate in lb/MWh.

(2) Sampling traverse points for NOx and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multihole 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.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NOx and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOx concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three 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 three points must be located along the measurement line that exhibited the highest average NOX concentration during the stratification test; or

(B) For turbines with a NOx standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOx concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NOx standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOx concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NOx emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NOx with no additional post-combustion NOx control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NOx emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NOx emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOx-diluent CEMS?

If you elect to install and certify a NOx-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NOx emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NOx emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NOx emission controls in accordance with §60.4340, the appropriate parameters must 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 §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation *to calculate the SO_2 emission rate:*

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664 × 10–7 = conversion constant, in lb/dscf-ppm

$(SO_2)c$ = average SO_2 concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flow meter (or flow meters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

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.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion 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.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NOX emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; 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.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.
ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

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. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 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.

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

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

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

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit 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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

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.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1_to Subpart KKKK of Part 60_Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New turbine firing natural gas, electric generating	[le] 50 MMBtu/h...	42 ppm at 15. percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive.	[le] 50 MMBtu/h...	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/ MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h...	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/ MWh)
New turbine firing fuels other than natural gas, electric generating	[le] 50 MMBtu/h...	96 ppm at 15 percent O_2 or 700 . ng/J of useful output (5.5 lb/ MWh).
New turbine firing fuels other than natural gas, mechanical drive.	[le] 50 MMBtu/h...	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and [le] 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h...	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine.	[le] 50 MMBtu/h...	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).

Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h.	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/ MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F.	[le] 30 MW output.	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output.	96 ppm at 15 percent O_2 or 590 ng/J of useful 75 output (4.7 lb/ MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes.........	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).