Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 17, 2006

Mr. David Kellermeyer, Vice President, EH&S
Northern Star Generation Services Company LLC
2929 Allen Parkway, Suite 2200
Houston, TX 77019

Re: Title V Air Operation Permit Revision
PROPOSED Permit Project No.: 1050217-005-AV
Mulberry Cogeneration Facility

Dear Mr. Kellermeyer:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Mulberry Cogeneration Facility located at 3600 County Road 555, Bartow, Polk County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the USEPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.

If you should have any questions, please contact Jonathan Holtom, P.E., at 850/921-9531.

Sincerely,

Trina L. Vielhauer (electronically signed)

Trina L. Vielhauer
Chief
Bureau of Air Regulation

TV/h
Enclosures

E-mail Copy furnished to:
Scott Osbourn, P.E., Golder Associates
Jason Waters, SWD
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

PROPOSED PERMIT DETERMINATION

Northern Star Generation Services Company LLC
Proposed Permit No.: 1050217-005-AV

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" to Northern Star Generation Services Company LLC, for the Mulberry Cogeneration Facility located at 3600 County Road 555, Bartow, Polk County, was clerked on April 3, 2006. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" was published in The Polk County Democrat on April 10, 2006. The DRAFT Title V Air Operation Permit was available for public inspection at the permitting authority's office in Tallahassee and the Department's Southwest District office in Tampa. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" was received on April 24, 2006.

II. Public Comment(s).

No comments were received by the Department from the public in response to the Draft permit and Public Notice. However, the applicant did provide one comment about the requirement to monitor the flow rate in the stack for use with their CEMS. Instead of a flow monitor, this facility utilizes the provisions of 40 CFR 75, Appendix D to determine heat input, volumetric flow and mass emissions. As a result of this comment, condition 7 of the permit was changed:

FROM:

A.34. Computation of Emissions.

1. Because the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute NO_X emissions.

2. Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained through the use of a calibrated flowmeter that records data on a continuous basis.

[Rule 62-210.370(2), F.A.C.]

TO:

A.34. Computation of Emissions.

1. Because the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute NO_X emissions.

2. Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:
   a. A calibrated flowmeter that records data on a continuous basis, if available; or

   b. The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

3. The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is

demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

[Rule 62-210.370(2), F.A.C.]

III. Conclusion.

The permitting authority will issue the PROPOSED Permit Number 0950203-006-AV, with the changes noted above.

STATEMENT OF BASIS

Polk Power Partners, L.P., Inc.
Mulberry Cogeneration Facility
Facility ID No.: 1050217
Polk County

Title V Air Operation Permit Revision
PROPOSED Permit Project No.: 1050217-005-AV
Revision of Title V Air Operation Permit No.: 1050217-002-AV

The renewed Title V Air Operation Permit, No. 1050217-002-AV, was effective on January 1, 2003. This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

The subject of this permit is the revision of Title V Air Operation Permit No. 1050217-002-AV, to incorporate the changes authorized by permit No. 150217-004-AC (issued concurrently with this permit); and to replace the Title V general Conditions with the latest version (Appendix TV-5, Title V Conditions) dated 3/28/05.

The construction permit (1050217-004-AC) was processed at the applicant's request for the following changes: 1) Turbine tuning as an allowed excess emission; 2) Incorporation of alternate startup/shutdown emission limits; 3) Revisions to the NO_X emission limit averaging time; and, 4) Increasing the heat input limits for the gas turbine by 5 percent on oil- and gas-firing. In addition, the following changes are being made to the Title V permit at the applicant's request without the need for a corresponding change in the construction permit: 1) Removing the secondary boiler from applicability from Title IV (Acid Rain); 2) Removing the requirement for the secondary gas-fired boiler to perform an annual visible emissions test; and, adding the authority to use Method 7E for NO_X compliance as an option to using Method 20. The applicant did not request an increase in any of the current permitted allowable annual emission rates for any existing emissions unit.

The subject facility consists of a 126 MW combined-cycle cogeneration unit which is comprised of 1 General Electric PG7111EA combustion turbine (CT), 1 Heat Recovery Steam Generator (HRSG) and 1 Secondary Boiler. The combustion turbine is regulated under Acid Rain Phase II.

The combustion turbine (CT) is a GE PG7111EA model with a nameplate rating of 82 MW at ISO conditions. The CT is allowed to burn natural gas or new No. 2 fuel oil. Natural gas is the primary fuel and new No. 2 fuel oil can be used permanently as back-up fuel. NO_X emissions are controlled by dry low-NO_X combustors and water-injection. The HRSG services a 44 MW steam generator and furnishes steam to other facilities. The CT and HRSG began commercial operation on August 10, 1994. The secondary boiler is for auxiliary steam. It is fired by natural gas. A portion of the exhaust gas from the combustion turbine is vented through the secondary boiler. CAM does not apply.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V Air Operation Permit Renewal application received July 5, 2002 and revision application dated September 19, 2005, this facility is not a major source of hazardous air pollutants (HAPs).

The following changes have been made to the Title V Air Operation permit as a result of this project:

1. To recognize excess emissions due to combustor tuning, a new excess emissions condition is added as Specific Condition **C.5.** The existing Specific Conditions **C.5. – C.17.** are renumbered as **C.6. – C.18.**

> **C.5.** Excess emissions resulting from a combustor tuning session shall be permitted provided the tuning session is performed in accordance with the manufacturer's specifications and in no case shall exceed 72 hours in any calendar year. A "tuning session" would occur after a combustor change-out, a repair to a combustor, or as required to maintain proper operation. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 1 day that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.
> [Rule 62-210.700(1) & (5), F.A.C.; and, 1050217-004-AC]

2. In order to establish an allowable emissions limitation for emissions of nitrogen oxides (NO_X) during periods of start up and shut down of the combustion turbine, and to clearly specify the averaging time for compliance with the NO_X limits, Specific Conditions **A.5.** & **A.6.** are changed:

FROM:

> **A.5.** Nitrogen Oxides. NO_X emissions shall not exceed 15 ppmvd @ 15% O_2 (52.7 lbs/hr and 230.7 TPY) when firing natural gas.
> [AC53-211670 and BACT Determination dated February 21, 1994]
>
> **A.6.** Nitrogen Oxides. NO_X emissions shall not exceed 42 ppmvd @ 15% O_2 (164.0 lbs/hr and 59.0 TPY) when firing new No. 2 fuel oil.
> [AC53-211670 and BACT Determination dated February 21, 1994]

TO:

> **A.5.** Nitrogen Oxides.
> 1. NO_X emissions shall not exceed 15 ppmvd @ 15% O_2 (52.7 lbs/hr and 230.7 TPY) when firing natural gas, based on a 4- hour rolling average as measured by the NO_X CEMS.
> 2. NO_X emissions shall not exceed 42 ppmvd @ 15% O_2 (164.0 lbs/hr and 59.0 TPY) when firing new No. 2 fuel oil, based on a 4- hour rolling average as measured by the NO_X CEMS.
>
> [AC53-211670 and BACT Determination dated February 21, 1994; and, 1050217-004-AC]

A.6. NO$_X$ Emissions During Start Up and Shut Down. The maximum allowable nitrogen oxide emissions resulting from a startup or shutdown of the CT shall not exceed an average of 52.7 lbs/hr when firing on natural gas nor 164 lbs/hr when firing on fuel oil, based on a 4-hour period commencing with the beginning of a start up or ending at the conclusion of a shut down of the unit. The 4-hour rolling average shall be based on all available data excluding calibration data and periods of emissions due to malfunction during the start up or shut down period.
[Rule 62-210.700(5), F.A.C.; and, 1050217-004-AC]

In addition, since the emissions are now specifically limited during periods of start up and shut down operations for the CT, the excess emissions provisions in Specific Condition **C.3.** are changed:

FROM:

C.3. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

TO:

C.3. Excess emissions resulting from a malfunction of the Combustion Turbine, or from startup, shutdown, or malfunction of the Secondary Boiler, shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1) & (5), F.A.C.]

3. To reflect the combustion turbine's ability to operate at a higher combustion temperature following the replacement of the combustor liners, Specific Conditions **A.1.** & **A.2.** are changed:

FROM:

A.1. Permitted Capacity. The operation rate shall not exceed 869 MMBtu/hr (LHV) at ISO conditions.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

A.2. Methods of Operation - Fuels.
The permittee shall fire natural gas or new No. 2 fuel oil. The primary fuel shall be natural gas with new No. 2 fuel oil as backup fuel. The fuel consumption rates (based on operation at 20° F) for the turbine shall not exceed those listed below:

Natural Gas		New No. 2 Fuel Oil	
M ft3/hr	MM ft3/yr	M lbs/hr	MM lbs/yr
1013.4	8877.4	55.6	40.0

New No. 2 fuel oil can be used permanently as backup fuel for no more than 720 hours per year.
[Rule 62-213.410, F.A.C.; and, AC53-211670]

TO:

A.1. Permitted Capacity. The operation rate shall not exceed 912 MMBtu/hr (LHV) at ISO conditions.
[Rules 62-4.160(2) & 62-210.200(PTE), F.A.C.; and 1050217-004-AC]

A.2. Methods of Operation - Fuels.
The permittee shall fire natural gas or new No. 2 fuel oil. The primary fuel shall be natural gas with new No. 2 fuel oil as backup fuel. The annual fuel consumption rates (based on operation at 20° F) for the turbine shall not exceed those listed below:

Natural Gas	New No. 2 Fuel Oil
MM ft3/yr	MM lbs/yr
8877.4	40.0

New No. 2 fuel oil can be used permanently as backup fuel for no more than 720 hours per year.
[Rule 62-213.410, F.A.C.; and, Permits AC53-211670 & 1050217-004-AC]

4. To provide assurance that the increase in the allowable heat input did not trigger PSD/New Source Review, the following record-keeping and reporting requirements are added as new Specific Conditions **A.32.** & **A.33.** The existing Specific Condition **A.32.** is renumbered to **A.34.**:

A.32. Monitoring and Reporting Requirements.

1. The permittee shall monitor the emissions of NO_X; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 10 years from the issuance date of this permit. Emissions shall be computed in accordance with Rule 62-210.370, F.A.C.
2. The permittee shall report to the Department within 60 days after the end of each year during which records must be generated under subparagraph 62-212.300(1)(e)1., F.A.C., setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:
    a. The name, address and telephone number of the owner or operator of the major stationary source;
    b. The annual emissions as calculated pursuant to subparagraph 62-212.300(1)(e)1., F.A.C.;
    c. If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and,
    d. Any other information that the owner or operator wishes to include in the report.
3. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1. and 2., F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

[Rule 62-212.300(1)(e), F.A.C.]

A.33. Computation of Emissions.

1. Because the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute NO_X emissions.
2. Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained through the use of a calibrated flowmeter that records data on a continuous basis.

[Rule 62-210.370(2), F.A.C.]

5. To update the permit with the latest version of the Title V General Conditions, all references to "APPENDIX TV-4, TITLE V CONDITIONS version dated 02/12/02" have been replaced by "APPENDIX TV-5, TITLE V CONDITIONS version dated 03/28/05".

6. To correct the improper identification of the auxiliary boiler as an Acid Rain Unit, all references to it (EU 002) in the Acid Rain Part have been removed. In addition, all occurrences throughout the permit where the auxiliary boiler was listed as being subject to Acid Rain, Phase II have also been removed.

7. At the applicant's request, the requirement to perform an annual visible emissions test for the secondary boiler has been removed by the addition of a new Specific Condition **B.9.** The existing Specific Condition **B.9.** has been renumbered to **B.10.** As a result of this request, Specific Condition **B.9.** is changed:

FROM:

B.9. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions.**

TO:

B.9. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit unless it operates more than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

B.10. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions.**

8. At applicant request, the annual test method for compliance with the NO_X emissions limit specified in Specific Condition **C.13.** (old Specific Condition **C.12.**) has been expanded to include Method 7E as an acceptable alternative.

9. The Applicant has chosen to use the Acid Rain NO_X CEMS as a continuous compliance determination method in order to be exempted from the Compliance Assurance Monitoring requirements of 40 CFR 64. As a result of this request, the existing Specific Conditions **A.23. – A.34.** have been renumbered as **A.24. – A.35.**, and a new Specific Condition **A.23.** is inserted:

A.23. Use of NO_X CEMS For Continuous Compliance. Pursuant to 40 CFR 64.2(b)(1)(vi), the applicant has elected to use the existing certified Acid Rain NO_X continuous emissions monitors for continuous compliance in order to be exempted from the Compliance Assurance Monitoring (CAM) requirements contained in 40 CFR 64. The permittee shall keep calibrated, maintain, and operate continuous emissions monitors (CEMS) to measure and record emissions of nitrogen oxides (NO_X) and oxygen (O_2) in a manner sufficient to demonstrate compliance with the standards of this permit.

(a) **Performance Specifications**. Each monitor shall be installed in a location that will provide emissions measurements representative of actual stack emissions. Each CEMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements. Each NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 7E or 20 as defined in Appendix A of 40 CFR 60.

(b) **Data Collection**. Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period during all periods of operation. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of the 1-hour block during which the unit combusted fuel. If the NO_X CEMS measures concentration on a wet basis, the permittee shall use DEP approved methods for correction of measured emissions to a dry basis (0% moisture). The O_2 (or CO_2) CEMS shall express the 1-hour emission rate values in terms of "percent oxygen by volume". The NO_X CEMS shall express the 1-hour emission averages in terms of "ppmvd corrected to 15% oxygen" for compliance with the BACT standard and, when requested by the Department, ISO corrected at 15% oxygen for the NSPS standard.

(c) **Compliance Averages**. Compliance with the 4-hour rolling average NO_X emissions standards shall be based on data collected by the CEMS. For purposes of determining compliance with the emission standards of this permit, missing data shall not be substituted. If monitoring data is authorized for exclusion (due to malfunction, or tuning), the 4-hour average shall be the average of the remaining valid 1-hour emission averages collected during actual operation. A 1-hour emissions average that includes any amount of oil firing shall only be included in the compliance average for oil firing. The CEMS used shall comply with 40 CFR 60.334(B)(2) (CFR dated 2004) which requires a minimum of 1 data point for each quadrant of a full unit operating hour or at least 2 data points (one in each of the two quadrants) when required quality assurance or maintenance activities are performed on the system.

(d) **Data Exclusion**. Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall record emissions data at all times including episodes of startup, shutdown, malfunction and combustor tuning. Emissions data recorded during periods of malfunctions or combustor tuning may only be excluded from the compliance averages in accordance with the requirements previously specified in this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for malfunctions and combustor tuning, unless specifically authorized in writing by the department's district office for longer periods. Data recorded during malfunctions or combustor tuning 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 startup, shutdown, malfunction and combustor tuning. 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. Excluded emissions data shall be summarized in the required quarterly report.

(e) **Monitor Availability**. Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-204.800, 62-210.700, 62-213.440, 62-4.070(3), 62-4.130, 62-4.160(8), F.A.C.; 40 CFR 60.7; and Applicant Request].

10. The applicant has also elected to utilize the provisions of 40 CFR 60, Subpart GG that allow the use of the Part 75 required NO_X CEMS to be used in lieu of water-to-fuel monitoring for the tracking and reporting of excess emissions. To ensure that all of the applicable requirements from Subpart GG are contained in the permit, Appendix GG, Standards of Performance for Stationary Gas Turbines has been added as a referenced attachment. As a result, Specific Condition **A.25.** (old A.24.) has been changed:

FROM:

A.25. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO_X emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within $\pm$5.0 percent and shall be approved by the Administrator.
[40 CFR 60.334(a)]

TO:

A.25. Alternate Monitoring Plan for Measuring NSPS Excess Emissions.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO_X emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within $\pm$5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. (See attached Appendix GG, Standards of Performance for Stationary Gas Turbines for specific details.)

1. At applicant request, the Acid Rain NO_X CEM data shall be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(b), Subpart GG (CFR dated 2004). The calibration

of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) (CFR dated 2004) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

2. When requested by the Department, the CEMS emission rates for NO_X on these units shall be corrected to ISO conditions to demonstrate compliance with the NO_X standards established in 40 CFR 60.332. With regard to NSPS Subpart GG, the NO_X CEMS data shall also be used to report excess emissions in accordance with 40 CFR 60.334(j)(1)(iii) and 40 CFR 60.7(c).

[40 CFR 60.334(a)&(b); and Applicant Request]

Northern Star Generation Services Company LLC
Mulberry Cogeneration Facility
Facility ID No.: 1050217
Polk County

Title V Air Operation Permit Revision

DRAFT Permit Project No.: 1050217-005-AV
1st Revision of Title V Air Operation Permit No.: 1050217-002-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
North Permitting Section
Telephone: 850/488-0114
Fax: 850/921-9533

Compliance Authority:
Southwest District Office
13051 N. Telecom Parkway
Temple Terrace, FL 33637-0926
Telephone: 813/744-6100
Fax: 813/744-6084

Title V Air Operation Permit Revision

DRAFT Permit No.: 1050217-005-AV
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Section **Page Number**

Permittee:
Polk Power Partners, L.P.
3600 County Road 555
Bartow, Florida 33831-0824

DRAFT Permit No.: 1050217-005-AV
Facility ID No.: 1050217
SIC No(s).: 49, 4911
Project: Title V Air Operation Permit Revision

The purpose of this permit is to revise and replace Title V Air Operation Permit, No. 1050217-002-AV, in order to incorporate the conditions of construction permit No. 1050217-004-AC, issued concurrently with this DRAFT Permit. This existing facility is located at 3600 County Road 555, Bartow, Polk County.

This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210 and 62-213. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Phase II Acid Rain Permit Application/NO_X Compliance Plan dated 7/2/02
Appendix GG, Standards Of Performance For Stationary Gas Turbines
Appendix I-1, List Of Insignificant Emissions Units And/Or Activities
Appendix SS-1, Stack Sampling Facilities Version Dated 10/07/96
Appendix TV-5, Title V Conditions Version Dated 03/28/05
Appendix U-1, List Of Unregulated Emissions Units And/Or Activities
Table 297.310-1, Calibration Schedule Version Dated 10/07/96
Figure 1 - Summary Report-Gaseous And Opacity Excess Emission And Monitoring System Performance (40 CFR 60, July, 1996)

Effective Date: January 1, 2003
Revision Effective Date: Day 55
Renewal Application Due Date: July 5, 2007
Expiration Date: December 31, 2007

Michael G. Cooke, Director
Division of Air Resource Management

MGC/jk/jh

Section I. Facility Information.

Subsection A. Facility Description.

This facility has a 126 MW combined cycle cogeneration unit which consists of 1 General Electric PG7111EA combustion turbine (CT), 1 Heat Recovery Steam Generator (HRSG) and 1 Secondary Boiler. The facility is fired with natural gas and new No. 2 fuel oil, with natural gas being the primary fuel and new No. 2 fuel oil as backup fuel.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V Air Operation Permit Renewal application received July 5, 2002, this facility is not a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
-001	Combustion Turbine (CT) with HRSG
-002	Secondary Boiler

Unregulated Emissions Units and/or Activities

-003	No. 2 Fuel Oil Tank (720,000 gal)

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Table 1-1: Summary of Air Pollutant Standards and Terms
Table 2-1: Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History
Statement of Basis

These documents are on file with the permitting authority:
Renewed Title V Air Operation Permit effective January 1, 2003.
Title V Air Operation Permit Revision Application received Electronically on September 19, 2005.
Request for additional information dated November 18, 2005
Additional information response received January 17, 2006

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-5, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-5, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard.
Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 1515
Lanham-Seabrook, MD 20703-1515
Telephone: 301/429-5018

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:

Cashier
Department of Community Affairs
State Emergency Response Commission
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

8. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. **Nothing was deemed necessary and ordered at this time.**
[Rule 62-296.320(1)(a), F.A.C.]

9. Not federally enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: Cooling Tower Drift Losses – Maintain proper water chemistry (pH & TDS) and equipment in accordance with the manufacturer's specifications; Abrasive Blast Activities – When practical, use of partial or total enclosures and use of grit materials verses sand. Limit annual activities; Surface Coating Activities - When practical, use of partial or total enclosures and limiting outdoor activities to times of favorable weather conditions to avoid off-site impacts; Dry Chemical Handling and Storage – Clean-up spills immediately, good housekeeping practices; Lawn & Ground Maintenance – Application of water to non-vegetative areas, as needed, landscaping and grass in other areas as necessary; Parking Areas – Application of water as necessary; and, Paved and Unpaved Roads – As needed, application of water, the removal of particulate matter from paved roads, limited site access to vehicles and vehicle speed limitations.
[Rule 62-296.320(4)(c)2., F.A.C.; and, proposed by applicant in the Title V Air Operation Permit Renewal application received July 5, 2002]

{Permitting note: This condition implements the requirements of Rules 62-296.320(4)(c)1., 3., & 4., F.A.C. (see Condition No. 57. of APPENDIX TV-5, TITLE V CONDITIONS)}

10. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

11. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of APPENDIX TV-5, TITLE V CONDITIONS.)}

12. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southwest District office.

Department of Environmental Protection
Southwest District Office
13051 N. Telecom Parkway
Temple Terrace, FL 33637-0926
Telephone: (813) 632-7600; Fax: 813/744-6458

13. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960
Telephone: 404/562-9155; Fax: 404/562-9163

14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

Section III. Emissions Unit and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	Combustion Turbine (CT) with HRSG

The combustion turbine (CT) is a GE PG7111EA model with a nameplate rating of 82 MW at ISO. The CT is allowed to burn natural gas or new No. 2 fuel oil. Natural gas is the primary fuel and new No. 2 fuel oil can be used permanently as back-up fuel. NO_X emissions are controlled by dry low-NO_X combustors and water-injection. The HRSG services a 44 MW steam generator and furnishes steam to other facilities. The CT and HRSG began commercial operation on August 10, 1994. This emissions unit is not subject the CAM requirements of 40 CFR 64 because the applicant has chosen to use the Acid Rain NO_X CEMS as a continuous compliance determination method.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; NSPS 40 CFR 60 Subpart A; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated February 21, 1994.}

In addition to the following specific conditions that apply to the emissions unit listed above, this emissions unit is also subject to the requirements of 40 CFR 60, Subpart GG, which are attached to this permit as Appendix GG - Standards of Performance for Stationary Gas Turbines:

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The operation rate shall not exceed 912 MMBtu/hr (LHV) at ISO conditions. [Rules 62-4.160(2) & 62-210.200(PTE), F.A.C.; and 1050217-004-AC]

A.2. Methods of Operation - Fuels.
The permittee shall fire natural gas or new No. 2 fuel oil. The primary fuel shall be natural gas with new No. 2 fuel oil as backup fuel. The annual fuel consumption rates (based on operation at 20° F) for the turbine shall not exceed those listed below:

Natural Gas	New No. 2 Fuel Oil
MM ft3/yr	MM lbs/yr
8,877.4	40.0

New No. 2 fuel oil can be used permanently as backup fuel for no more than 720 hours per year. [Rule 62-213.410, F.A.C.; and, Permits AC53-211670 & 1050217-004-AC]

A.3. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8760 hours/year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging time for conditions A.5. – A.10. are based on the specified averaging time of the applicable test method.}

A.4. All emission limits in **Specific Conditions A.5.** through **A.10.** are based on operation at 59°F and 60% relative humidity (ISO conditions).
[AC53-211670]

A.5. Nitrogen Oxides.
1. NO_X emissions shall not exceed 15 ppmvd @ 15% O_2 (52.7 lbs/hr and 230.7 TPY) when firing natural gas, based on a 4- hour rolling average as measured by the NO_X CEMS.
2. NO_X emissions shall not exceed 42 ppmvd @ 15% O_2 (164.0 lbs/hr and 59.0 TPY) when firing new No. 2 fuel oil, based on a 4- hour rolling average as measured by the NO_X CEMS.
[AC53-211670 and BACT Determination dated February 21, 1994; and, 1050217-004-AC]

A.6. NO_X Emissions During Start Up and Shut Down. The maximum allowable nitrogen oxide emissions resulting from a startup or shutdown of the CT shall not exceed an average of 52.7 lbs/hr when firing on natural gas nor 164.0 lbs/hr when firing on fuel oil, based on a 4-hour period commencing with the beginning of a start up or ending at the conclusion of a shut down of the unit. The 4-hour rolling average shall be based on all available data excluding calibration data and periods of emissions due to malfunction during the start up or shut down period. (Note: For excess emissions regarding malfunctions, see Specific Condition **C.3.**)
[Rule 62-210.700(5), F.A.C.; and, 1050217-004-AC]

A.7. Sulfur Dioxide. The maximum sulfur content of the new No. 2 fuel oil shall not exceed 0.10 percent, by weight.
[AC53-211670 and BACT Determination dated February 21, 1994]

A.8. Reserved.

A.9. Carbon Monoxide. CO emissions shall not exceed 25 ppmvd @ 15% O_2 (53.0 lbs/hr and 232.0 TPY) when firing natural gas.
[AC53-211670 and BACT Determination dated February 21, 1994]

A.10. Carbon Monoxide. CO emissions shall not exceed 75.3 lbs/hr and 27.1 TPY when firing new No. 2 fuel oil.
[AC53-211670 and BACT Determination dated February 21, 1994]

Test Methods and Procedures

A.11. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not

constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
[40 CFR 60.8(c)]

A.12. Compliance with standards in 40 CFR 60, other than opacity, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
[40 CFR 60.11(a)]

A.13. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

A.14. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

A.15. To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired. (See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.335(a)]

A.16. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in this permit, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph 40 CFR 60.335(f). (See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.335(b)]

A.17. The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 1072-96, D 3031-81(86), D 4084-94, D 3246-92, or the latest edition of the above ASTM methods shall be used for the sulfur content of gaseous fuels (incorporated by reference-see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator. (See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.335(d)]

A.18. The owner or operator shall determine compliance with the sulfur content standard in **Specific Condition A.7.** by using ASTM D 2880-96, or the latest edition. (See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.335(d)]

A.19. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335(a) and 40 CFR 60.335(d) of 40 CFR 60.335 to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency. (See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.335(e)]

A.20. Reserved

Monitoring of Operations

A.21. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).

(See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.334(b)(1) and (2)]

A.22. The permittee shall monitor sulfur content and nitrogen content of natural gas fired in the turbine as follows:

Custom Fuel Monitoring Schedule for Natural Gas

1. Monitoring of fuel nitrogen content shall not be required when firing natural gas.

2. Sulfur Monitoring:

   a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-90(94)E-1, ASTM D3031-81(86), ASTM D 3246-92, and ASTM D4084-94, or the latest edition of the above ASTM methods as referenced in 40 CFR 60.335(d).

   b. This custom fuel monitoring schedule became effective on August 8, 1994. Sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein, the applicant may begin monitoring as per the requirements of 2(c).

c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per year. This monitoring shall be conducted during the first and third quarters of each calendar year.

d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be reexamined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change for reexamination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being reexamined.

(See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[40 CFR 60.334(b)(2); and, AC 53-211670]

Continuous Monitoring Requirements

A.23. Use of NO_X CEMS For Continuous Compliance. Pursuant to 40 CFR 64.2(b)(1)(vi), the applicant has elected to use the existing certified Acid Rain NO_X continuous emissions monitors for continuous compliance in order to be exempted from the Compliance Assurance Monitoring (CAM) requirements contained in 40 CFR 64. The permittee shall keep calibrated, maintain, and operate continuous emissions monitors (CEMS) to measure and record emissions of nitrogen oxides (NO_X) and oxygen (O_2) in a manner sufficient to demonstrate compliance with the standards of this permit.

(a) **Performance Specifications**. Each monitor shall be installed in a location that will provide emissions measurements representative of actual stack emissions. Each CEMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements. Each NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 7E or 20 as defined in Appendix A of 40 CFR 60. .

(b) **Data Collection**. Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period during all periods of operation. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of the 1-hour block during which the unit combusted fuel. If the NO_X CEMS measures concentration on a wet basis, the permittee shall use DEP approved methods for correction of measured emissions to a dry basis (0% moisture). The O_2 (or CO_2) CEMS shall express the 1-hour emission rate values in terms of "percent oxygen by volume". The NO_X CEMS shall express the 1-hour emission averages in terms of "ppmvd corrected to 15% oxygen" for compliance with the BACT standard and, when requested by the Department, ISO corrected at 15% oxygen for the NSPS standard.

(c) **Compliance Averages**. Compliance with the 4-hour rolling average NO_X emissions standards shall be based on data collected by the CEMS. For purposes of determining compliance with the emission standards of this permit, missing data shall not be substituted. If monitoring data is authorized for exclusion (due to malfunction, or tuning), the 4-hour average shall be the average of the remaining valid 1-hour emission averages collected during actual operation. A 1-hour emissions average that includes any amount of oil firing shall only be included in the compliance average for oil firing. The CEMS used shall comply with 40 CFR 60.334(B)(2) (CFR dated 2004) which requires a minimum of 1 data point for each quadrant of a full unit operating hour or at least 2 data points (one in each of the two quadrants) when required quality assurance or maintenance activities are performed on the system.

(d) **Data Exclusion**. Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall record emissions data at all times including episodes of startup, shutdown, malfunction and combustor tuning. Emissions data recorded during periods of malfunctions or combustor tuning may only be excluded from the compliance averages in accordance with the requirements previously specified in this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for malfunctions and combustor tuning, unless specifically authorized in writing by the department's district office for longer periods. Data recorded during malfunctions or combustor tuning 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 startup, shutdown, malfunction and combustor tuning. 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. Excluded emissions data shall be summarized in the required quarterly report.

(e) **Monitor Availability**. Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-204.800, 62-210.700, 62-213.440, 62-4.070(3), 62-4.130, 62-4.160(8), F.A.C.; 40 CFR 60.7; and Applicant Request].

A.24. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
[40 CFR 60.7(c)(1), (2), (3), and (4)]

A.25. Alternate Monitoring Plan for Measuring NSPS Excess Emissions.
(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO_X emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within $\pm$5.0 percent and shall be approved by the Administrator.
(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. (See attached Appendix GG, Standards of Performance for Stationary Gas Turbines for specific details.)
1. At applicant request, the Acid Rain NO_X CEM data shall be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(b), Subpart GG (CFR dated 2004). The calibration of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) (CFR dated 2004) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.
2. When requested by the Department, the CEMS emission rates for NO_X on these units shall be corrected to ISO conditions to demonstrate compliance with the NO_X standards established in 40 CFR 60.332. With regard to NSPS Subpart GG, the NO_X CEMS data shall also be used to report excess emissions in accordance with 40 CFR 60.334(j)(1)(iii) and 40 CFR 60.7(c).

[40 CFR 60.334(a)&(b); and Applicant Request]

Recordkeeping and Reporting Requirements

A.26. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results.
[AC 53-211670]

A.27. Records of sample analysis and fuel supply pertinent to the "Custom Fuel Monitoring Schedule for Natural Gas" in **Specific Condition A.22.** shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.
[AC 53-211670]

A.28. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:
a. *Nitrogen oxides*. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the permitted nitrogen oxide standard by the initial performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the initial performance test. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas

turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a). (See also APPENDIX GG, Standards of Performance for Stationary Gas Turbines, attached.)
[Rule 62-296.800, F.A.C.; and, 40 CFR 60.334(c)(1)]

A.29. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b)]

A.30. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

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

[40 CFR 60.7(d)(1) and (2)]

A.31. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or

operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.
(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)]

A.32. The permittee shall maintain a file of all measurements, including continuous monitoring systems, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f) and Rule 62-213.440(1)(b)2.b., F.A.C.]

A.33. Monitoring and Reporting Requirements.
1. The permittee shall monitor the emissions of NO_X; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 10 years from the issuance date of this permit. Emissions shall be computed in accordance with Rule 62-210.370, F.A.C.
2. The permittee shall report to the Department within 60 days after the end of each year during which records must be generated under subparagraph 62-212.300(1)(e)1., F.A.C., setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:
   a. The name, address and telephone number of the owner or operator of the major stationary source;
   b. The annual emissions as calculated pursuant to subparagraph 62-212.300(1)(e)1., F.A.C.;
   c. If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and,
   d. Any other information that the owner or operator wishes to include in the report.
3. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1. and 2., F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

[Rule 62-212.300(1)(e), F.A.C.]

A.34. Computation of Emissions.
1. Because the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute NO_X emissions.
2. Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:
   a. A calibrated flowmeter that records data on a continuous basis, if available; or

b. The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

3. The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

[Rule 62-210.370(2), F.A.C.]

A.35. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions**.

Subsection B. This section addresses the following emissions unit(s).

E.U. ID No.	**Brief Description**
-002	Secondary Boiler

The secondary boiler is for auxiliary steam. It is fired by natural gas. A portion of the exhaust gas from the combustion turbine is vented through the secondary boiler. NO_X emissions are controlled with dry-low NO_X combustion technology. This emissions unit began commercial operation on August 10, 1994.

{Permitting notes: The emissions unit is regulated under: 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated February 21, 1994. Subpart Dc does not specify any emissions standards for units that combust only natural gas. Therefore, only the NSPS, Subpart Dc requirements for notification and record keeping apply.}

The following specific conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The operation rate shall not exceed 99 MMBtu/hr (LHV) at ISO conditions.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

B.2. Methods of Operation - Fuels.
The only fuel allowed to be burned is natural gas. The fuel consumption rates (based on operation at 20° F) for the secondary boiler shall not exceed those listed below:

Natural Gas	
M ft3/hr	MM ft3/yr
104.2	450.2*

*Based on maximum firing rate for 4,320 hours per year.
[Rule 62-213.410, F.A.C.; and, AC 53-211670]

B.3. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging time for conditions B.4. – B.8. are based on the specified averaging time of the applicable test method.}

B.4. Nitrogen Oxides. NO_X emissions shall not exceed 18.3 lbs/hr and 80.0 TPY when firing natural gas.
[AC53-211670 and BACT Determination dated February 21, 1994]

B.5. Nitrogen Oxides. NO_X emissions shall not exceed 23.4 lbs/hr and 8.4 TPY when firing new No. 2 fuel oil in the combustion turbine.
[AC53-211670 and BACT Determination dated February 21, 1994]

B.6. Sulfur Dioxide. The maximum sulfur content of the new No. 2 fuel oil shall not exceed 0.10 percent, by weight.
[AC53-211670 and BACT Determination dated February 21, 1994]

B.7. Carbon Monoxide. CO emissions shall not exceed 12.6 lbs/hr and 55.2 TPY when firing natural gas.
[AC53-211670 and BACT Determination dated February 21, 1994]

B.8. Carbon Monoxide. CO emissions shall not exceed 13.4 lbs/hr and 4.8 TPY when firing new No. 2 fuel oil in the combustion turbine.
[AC53-211670 and BACT Determination dated February 21, 1994]

B.9. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit unless it operates more than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

B.10. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions.**

Subsection C. Common Conditions.

E.U. ID No.	**Brief Description**
-001	Combustion Turbine with HRSG
-002	Secondary Boiler

The following specific conditions apply to the emissions units listed above:

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging time for conditions C.1. – C.2. are based on the specified averaging time of the applicable test method.}

C.1. Visible Emissions. Visible emissions shall not exceed 10 percent opacity when firing natural gas.
[AC53-211670]

C.2. Visible Emissions. Visible emissions shall not exceed 20 percent opacity when firing new No. 2 fuel oil in the combustion turbine.
[AC53-211670]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

C.3. Excess emissions resulting from a malfunction of the Combustion Turbine, or from startup, shutdown, or malfunction of the Secondary Boiler, shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1) & (5), F.A.C.]

C.4. 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.
[Rule 62-210.700(4), F.A.C.]

C.5. Excess emissions resulting from a combustor tuning session shall be permitted provided the tuning session is performed in accordance with the manufacturer's specifications and in no case shall exceed 72 hours in any calendar year. A "tuning session" would occur after a combustor change-out, a repair to a combustor, or as required to maintain proper operation. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 1 day that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.
[Rule 62-210.700(1) & (5), F.A.C.; and, 1050217-004-AC]

Test Methods and Procedures

C.6. 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 the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.7. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity as defined below. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load 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 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.]

C.8. Calculation of Emission Rate. 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.]

C.9. 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, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.

(e) 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.]

C.10. 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.]

C.11. The permittee shall comply with the requirements contained in APPENDIX SS-1, Stack Sampling Facilities, attached to this permit.

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

C.12. 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.

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 Rule 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

(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 may 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 Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

C.13. Annual compliance with the NO_X, CO, SO_2 and visible emission standards shall be determined by the following reference methods as described in 40 CFR 60, Appendix A and adopted by reference in Rule 62-297, F.A.C.

NO_X: EPA Method 20 or Method 7E
CO: EPA Method 10
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9

The owner or operator is allowed to make compliance demonstrations for NO_X emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_X monitor. The applicable span value specified in 40 CFR Part 75 shall be used instead of that specified 40 CFR 60.335(c).
[AC 53-211670 & 1050217-003-AC]

Continuous Monitoring Requirements

C.14. The power output from the generators shall be metered and continuously recorded. The data shall

be logged daily and maintained so that it can be provided to DEP upon request.
[AC 53-211670]

Recordkeeping and Reporting Requirements

C.15. The owner of operator shall notify the Southwest District Office of the Department, in writing, at least 15 days prior to the date on which each test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
[Rule 62-297.310(7)(a)9., F.A.C.]

C.16. In case of excess emissions resulting from malfunctions, Polk Power Partners, L.P. shall notify the Department's Southwest District Office 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.]

C.17. 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.]

Reasonable Assurances

C.18. Any other operating parameters established during compliance testing and/or inspections, that will ensure the proper operation of this facility, are considered part of this operating permit. Said operating parameters include, but are not limited to: Fuel flow rate and heat input rate.
[Rule 62-4.070(3), F.A.C.]

Section IV. This section is the Acid Rain Part.

Operated by: Polk Power Partners, L.P.
ORIS code: 54426

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions unit(s) listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
-001	Combustion Turbine with HRSG

A.1. The Phase II permit application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated July 2, 2002
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2003	2004	2005	2006	2007
-001	01	**SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73**	0*	0*	0*	0*	0*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 or 3 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
1. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-

Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: none

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions - Applicable Requirements, F.A.C.]

Referenced Attachments

Phase II Acid Rain Application/NO_X Compliance Plan

Appendix A-1, Abbreviations, Definitions, Citations, and Identification Numbers

Appendix GG, Standards of Performance for Stationary Gas Turbines

Appendix H-1, Permit History

Appendix I-1, List of Insignificant Emissions Units and/or Activities

Appendix SS-1, Stack Sampling Facilities

Appendix TV-5, Title V Conditions

Appendix U-1, List of Unregulated Emissions Units and/or Activities

Table 1-1, Summary of Air Pollutant Standards and Terms

Table 2-1, Compliance Requirements

Table 297.310-1, Calibration Schedule

Figure 1 - Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance

Phase II Acid Rain Permit Application/NO_X Compliance Plan

Appendix A-1, Abbreviations, Definitions, Citations, and Identification Numbers (Version Dated 2/5/97)

Appendix GG, Standards of Performance for Stationary Gas Turbines (Version Dated 7/08/04)

Appendix GG-Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

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

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

§ 60.331 Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(o) *Garrison facility* means any permanent military installation.

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

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

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

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

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

(1) The NO_X emissions are higher than the applicable emission limit in Sec. 60.332;

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

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

(u) Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

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

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

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

§ 60.332 Standard for nitrogen oxides.

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

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

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

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and
F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

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

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

where:
STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and
F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

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

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

Fuel-bound nitrogen (% by weight)	F (NO_X% by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

Where:
N = the nitrogen content of the fuel (percent by weight).or:
Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by Sec. 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

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

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

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

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

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

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

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

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

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

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

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

§ 60.333 Standard for sulfur dioxide.

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

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

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

§ 60.334 Monitoring of operations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in Sec. 75.19(c)(1)(iv)(H) of this chapter.

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

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

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

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in Sec. 60.332). The nitrogen content of the fuel shall be determined using methods described in Sec. 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Sec. 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under Sec. 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

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

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with Sec. 60.332, as established during the performance test required in Sec. 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in Sec. 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a ``4-hour rolling average NO_X concentration'' is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

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

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under Sec. 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

Sec. 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in Sec. 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

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

(A) [Reserved]

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

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

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O2, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O2, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in Sec. 60.332 and shall meet the performance test requirements of Sec. 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\ e^{19\,(H_o-0.00633)}\ (288[deg]K/Ta)^{1.53}$$

Where:
NO_X = emission concentration of NO_X at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,
NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O2,
P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,
P_o = observed combustor inlet absolute pressure at test, mm Hg,
H_o = observed humidity of ambient air, g H2O/g air,
e = transcendental constant, 2.718, and
T_a = ambient temperature, [deg]K.

(2) The 3-run performance test required by Sec. 60.8 must be performed within 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding theserequirements, performance testing is not required for any emergency fuel (as defined in Sec. 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in Sec. 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in Sec. 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in Sec. 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under Sec. 60.334(e), then the initial performance test required under Sec. 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under Sec. 60.332 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under Sec. 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in Sec. 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under Sec. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in Sec. 60.8 to ISO standard day conditions.

Appendix H-1, Permit History

Appendix H-1: Permit History

Northern Star Generation Services Company, LLC.
Mulberry Cogeneration Facility

PROPOSED Permit No.: 1050217-005-AV
Facility ID No.: 1050217

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type [1]
All	Facility	AC53-211670/ PSD-FL-187	11/24/1992	12/31/1995	Construction (new)
All	Facility	AC53-211670/ PSD-FL-187	8/3/1994	12/31/1997	Construction (mod.)
All	Facility	1050217-001-AV	01/01/1998	12/31/2002	Initial
-001	Combustion Turbine (CT) with HRSG	1050217-003-AC/ PSD-FL-187A	10/28/2002	10/28/2007	Construction (mod.)
All	Facility	1050217-002-AV	01/01/2003	12/31/2007	Renewal
All	Facility	1050217-004-AC	05/05/2006	3/15/2007	Construction (mod.)
All	Facility	1050217-005-AV	(day 55)	12/31/2007	Revision

[1] Project Type (select one): Title V: Initial, Revision, Renewal, or Admin. Correction; Construction (new or mod.); or, Extension (AC only).

Appendix I-1, List of Insignificant Emissions Units and/or Activities

Appendix I-1: List of Insignificant Emissions Units and/or Activities.

Northern Star Generation Services Company, LLC.
Mulberry Cogeneration Facility

PROPOSED Permit No.: 1050217-005-AV
Facility ID No.: 1050217

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. Comfort heating < 1 MMBtu/hr
2. Internal combustion engines - mobile sources
3. Non-industrial vacuum cleaning
4. Refrigeration equipment
5. Vacuum pumps for labs
6. Steam cleaning equipment
7. Sanders < 5 sq. ft.
8. Lab equipment used for chemical or physical analyses
9. Brazing, soldering or welding equipment
10. Emergency generators < 32,000 gal/yr
11. General purpose engines < 32,000 gal/yr
12. Fire and safety equipment
13. Surface coating > 5% VOC; 6 gal/month
14. Surface coating < 5% VOC
15. Freshwater cooling towers. The cooling towers do not use chromium-based treatment chemicals.

Appendix SS-1,
Stack Sampling Facilities (version dated 10/7/96)

Appendix TV-5,
Title V Conditions (version dated 3/28/05)

Appendix U-1, List of Unregulated Emissions Units and/or Activities

Appendix U-1: List of Unregulated Emissions Units and/or Activities.

Northern Star Generation Services Company, LLC. **PROPOSED Permit No.:** 1050217-005-AV
Mulberry Cogeneration Facility **Facility ID No.:** 1050217

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

E.U. ID No.	**Brief Description of Emissions Units and/or Activity**
-003	New No. 2 Fuel Oil Tank (720,000 gal)

Table 1-1, Summary of Air Pollutant Standards and Terms

Table 1-1, Summary of Air Pollutant Standards and Terms

Northern Star Generation Srvices Company, LLC
Mulberry Cogeneration Facility

PROPOSED Permit No.: 1050217-005-AV
Facility ID No.: 1050217

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
-002	Secondary Boiler

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
NO_X	natural gas	8760		18.3	80.0				III.B.4.
NO_X	No. 2 Oil fired in CT	720		23.4	8.4				III.B.5
SO_2	No. 2 Oil fired in CT	720	0.10 % by weight						III.B.6.
CO	natural gas	8760		12.6	55.2				III.B.7.
CO	No. 2 Oil fired in CT	720		13.4	4.8				III.B.8.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

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Table 2-1, Summary of Compliance Requirements

Table 2-1, Summary of Compliance Requirements

Northern Star Generation Srvices Company, LLC
Mulberry Cogeneration Facility

PROPOSED Permit No.: 1050217-005-AV
Facility ID No.: 1050217

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
-001	Combustion Turbine with HRSG
-002	Secondary Boiler

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
NO_X	Natural gas and No. 2 Oil	EPA Method 20 or 7E	annual	26-Aug	1 hour	YES	III.C.12.
CO	Natural gas and No. 2 Oil	EPA Method 10	annual	26-Aug	1 hour		III.C.12.
SO_2	Natural gas	ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81***	see custom fuel monitoring schedule		not applicable		III.A.18.; A.22. and C.12.
	No. 2 Oil	ASTM D 2880-71***	From bulk storage: after each shipment no bulk storage: daily		not applicable not applicable		III.A.18., C.12.
VE	Natural gas and No. 2 Oil	EPA Method 9	annual	26-Aug			III.C.12. & 13.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system
*** The latest edition of the ASTM methods may be used.

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TABLE 297.310-1, CALIBRATION SCHEDULE
(version dated 10/07/96)

TABLE 297.310-1 CALIBRATION SCHEDULE
(version dated 10/07/96)

[Note: This table is referenced in Rule 62-297.310, F.A.C.]

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

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Figure 1 - Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance (40 CFR 60, July, 1996)

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____

Total source operating time in reporting period [1]: ____________________

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ % [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ % [2]

1 For opacity, record all times in minutes. For gases, record all times in hours.

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

Note: *On a separate page, describe any changes since last quarter in CMS, process or controls.*

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

Name: ____

Signature: ____ *Date*: ____________________

Title: ____