Florida Department of Environmental Protection

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PERMITTEE

Lyondellbasell Flavors & Fragrances, LLC
P.O. Box 389
Jacksonville, Florida 32201-0389

Authorized Representative:
Mr. Mike Templeton, Director of Manufacturing

Air Permit No. 0310039-013-AC
Permit Expires: December 31, 2012
Issue Date: December 8, 2010
Lyondellbasell Flavors & Fragrances, LLC
Minor Source Air Construction Permit
Steam Repowering Project

This is the final air construction permit, which authorizes the steam repowering project which includes the construction of Boiler No. 1, a 140 MMBtu per hour maximum heat input steam generating Boiler fired by Natural Gas (NG), Ultra Low Sulfur Distillate Fuel Oil (ULSD), and process derived fuel (PDF), the reduced utilization of Boiler Nos. 6 and 7, and the removal of Boiler Nos. 4 and 5. The proposed work will be conducted at the Lyondellbasell Flavors & Fragrances, LLC, which is a chemical manufacturing plant (Standard Industrial Classification No. 2869). The facility is located in Duval County at the Foot of 61st Street in Jacksonville, Florida. The UTM coordinates are Zone 17, 435.6 km East, and 3360.75 km North.

This final permit is organized by the following sections.

Section 1. General Information

Section 2. Administrative Requirements

Section 3. Emissions Unit Specific Conditions

Section 4. Prevention of Significant Deterioration Requirements

Section 5. Appendices

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit.

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and is not subject to the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

Christopher L. Kirts, P.E.
District Air Program Administrator

08 Dec 2010
(Date)

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on Dec. 8th 2010 to the persons listed below.

Mike Templeton, Lyondellbasell Flavors & Fragrances, LLC: michael.templeton@lyondellbasell.com
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Clerk Stamp

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

Marjorie M. Riley 12·8·10

(Clerk) (Date)

FACILITY AND PROJECT DESCRIPTION

Existing Facility

This facility processes Crude Sulfate Turpentine, gum turpentine, and other chemicals to produce synthetic flavor and fragrance chemicals and also chemical intermediates. The facility operates four (4) steam-generating boilers on site. The existing facility consists of the following emissions units:

Facility ID No. 0310039	
ID No.	**Emission Unit Description**
-004	Boiler No. 4
-005	Boiler No. 5
-006	Boiler No. 6
-011	Boiler No. 7

Proposed Project

This air construction permit authorizes the steam repowering project which includes the construction of boiler No. 1, a 140 MMBtu per hour maximum heat input steam generating boiler fired by NG, ULSD, and PDF, the reduced utilization of Boiler Nos. 6 and 7, and the removal of Boiler Nos. 4 and 5. Boiler Nos. 6 and 7 (EU Nos. 006 and 011) shall be subject to limited operation during Boiler No. 1 start-up, shutdown, malfunction, or maintenance. This project will add or modify the following emissions unit(s):

Facility ID No. 0310039	
ID No.	**Emission Unit Description**
032	Boiler No. 1 fired by NG, ULSD No. 2 Fuel Oil, and Process Derived Fuel; or any combination of these fuels
004	Boiler No. 4
005	Boiler No. 5
006	Boiler No. 6
011	Boiler No. 7

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility has no units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.

SECTION 2. ADMINISTRATIVE REQUIREMENTS (FINAL)

1. Permitting Authority: The permitting authority for this project is the Northeast District Office, Air Resources Section, Florida Department of Environmental Protection (Department). The Northeast District Office's mailing address is 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590. All documents related to applications for permits to operate an emissions unit shall be submitted to the Northeast District Office. The Permitting Authority's telephone number is 904/256-1700.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the City of Jacksonville (COJ), Environmental and Compliance Department (E&CD), Environmental Quality Division (EQD). The mailing address and phone number of the COJ, E&CD, EQD is: City of Jacksonville, Environmental and Compliance Department, Environmental Quality Division, Third Floor, 407 West Laura St., Jacksonville, FL 32202.. The Compliance Authority's telephone number is 904/255-7100.

3. Appendices: The following Appendices are attached as part of this permit:

   a. Appendix A. Citation Formats and Glossary of Common Terms;

   b. Appendix B. General Conditions;

   c. Appendix C. Common Conditions

   d. Appendix D. Common Testing Requirements

   e. Appendix E. 40 CFR 60, Subpart A, General Conditions

   f. Appendix BACT

   g. Appendix JEPB

   h. Appendix CEMS

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

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

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1) (a), F.A.C.]

7. Source Obligation:

   a. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was

established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

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

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

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

A. Boiler No. 1

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
032	Boiler No. 1 fired by NG , ULSD, and PDF; or any combination of these fuels -- The Boiler is subject to Nitrogen oxides (NO_x), Sulfur dioxide(SO_2), and opacity limitations in 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Additional restrictions have been added in Section 4 regarding Prevention of Significant Deterioration (PSD).

EQUIPMENT

A.1. Equipment Name: The permittee is authorized to install Boiler No. 1. Boiler No. 1 was originally designed with a maximum heat input of 180 MMBtu per hour (circa 1996) firing NG or No. 2 fuel oil. The boiler will be retrofitted with a new low NOx burner and a variable forced draft fan resulting in a derated maximum heat input of 140 MMBtu per hour firing NG, ULSD, or PDF, or any combinations of these fuels.

[Application No. 0310039-013-AC]

PERFORMANCE RESTRICTIONS

A.2. Permitted Capacity: Boiler No. 1 shall be limited to a maximum heat input of 140 MMBtu per hour.

[Rule 62-210.200(PTE), F.A.C.; Applicant's Request]

A.3. Authorized Fuel: Fuels shall be limited to [1]NG, [1]ULSD, PDF, or any combination of these fuels.

[[1]BACT Determination, Application No. 0310039-013-AC and Rule 62-210.200(PTE), F.A.C.]

A.4. Operation: The hours of operation are not limited (i.e., 8760 hours per year).

[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

A.5. a. Emissions Standards for NO_x: Individual fossil fuel firing (ULSD or NG).

On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only oil or NG shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBtu
NG and ULSD		
(i) Low heat release rate	43	0.10

(ii) High heat release rate	86	0.20

b. Emissions Standards for NO_x: Simultaneous fossil fuel (ULSD and NG) firing.

On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of ULSD and NG shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go}= Appropriate emission limit from paragraph 5. (a)(1) for combustion of NG or YLSD, ng/J (lb/MMBtu);

H_{go}= Heat input from combustion of NG or ULSD, J (MMBtu);

EL_{ro}= Appropriate emission limit from paragraph 5. (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro}= Heat input from combustion of residual oil, J (MMBtu);

EL_c= Appropriate emission limit from paragraph 5. (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c= Heat input from combustion of coal, J (MMBtu).

c. Emissions Standards for NO_x: Simultaneous fossil fuel firing (ULSD and/or NG) with byproduct/waste fuel (PDF).

On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, ULSD, or NG with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and NG of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_Xemission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go}= Appropriate emission limit from paragraph 5. (a)(1) for combustion of NG or ULSD, ng/J (lb/MMBtu);

H_{go}= Heat input from combustion of NG, ULSD and gaseous byproduct/waste, J (MMBtu);

EL_{ro}= Appropriate emission limit from paragraph 5. (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);

H_{ro}= Heat input from combustion of residual oil, J (MMBtu);

EL_c= Appropriate emission limit from paragraph 5. (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c= Heat input from combustion of coal, J (MMBtu).

[40 CFR 60.44b (a,b,c,d), Application No.0310039-013-AC and Rule 62-204.800, F.A.C.]

Please Note: While firing byproduct/waste fuel (PDF) independently Boiler No. 1 shall not be subject to a NO_x limitation under 40 CFR 60, Subpart Db, however the boiler is subject to the NO_x limitation to avoid triggering PSD applicability. See Section 4, Prevention of Significant Deterioration Requirements, A.7.e.

A.6. Emission Limiting Standards for Opacity and Particulate Matter

a. Opacity

i. On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR 60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, ULSD, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

ii. The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

[40 CFR 60. 43b(f), Rule 62-204.800, F.A.C.]

iii. The Boiler shall be subject to Visible Emissions - 20 percent opacity except for one six-minute period per hour during which opacity shall not exceed 27 percent.

[Rule 62-296.406(1), F.A.C.]

b. Particulate Matter

The Boiler shall be subject to a Best Available Control Technology Determination for particulate matter emissions.

[Rule 62-296.406(2), F.A.C.]

A.7. a. Emission Limiting Standards for SO_2 while burning ULSD:

Except as provided in paragraphs (b), (c), (d), or (j) of 40 CFR 60.42b, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s= SO_2 emission limit, in ng/J or lb/MMBtu heat input;

K_a= 520 ng/J (or 1.2 lb/MMBtu);

K_b= 340 ng/J (or 0.80 lb/MMBtu);

H_a= Heat input from the combustion of coal, in J (MMBtu); and

H_b= Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and ULSD is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of NG, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

b. Compliance with the SO_2 emission limits, fuel oil sulfur limits, and/or SO_2 percent reduction requirements in section a. above are determined on a 30-day rolling average basis.

c. The SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

d. Percent reduction requirements are not applicable to affected facilities combusting only ULSD. The owner or operator of an affected facility combusting ULSD shall demonstrate that the ULSD meets the definition of ULSD by:

(1) Following the performance testing procedures as described in 40 CFR 60.45b(c) or 40 CFR 60.45b(d), and following the monitoring procedures as described in 40 CFR 60.47b(a) or 40 CFR 60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or

(2) maintaining fuel records as described in 40 CFR 60.49b(r).

[40 CFR 60. 42b(a), (e), (g), and (j), Rule 62-204.800, F.A.C.]

e. The Boiler shall be subject to a Best Available Control Technology Determination for sulfur dioxide emissions.

[Rule 62-296.406(3), F.A.C.]

NSPS COMPLIANCE AND PERFORMANCE TEST METHODS FOR NITROGEN OXIDES SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.8. To determine compliance with the emission limits for NO_x required under 40 CFR 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under 40 CFR 60.8 using the continuous system for monitoring NO_x under 40 CFR 60.48(b).

a. For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under 40 CFR 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

b. Following the date on which the initial performance test is completed or required to be completed under 40 CFR 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts NG, ULSD, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall, upon request, determine, compliance with the NO_x standards in 40 CFR 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to 40 CFR 60.48b(g)(1) or 40 CFR 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the

average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

[40 CFR 60.46b(e), Rule 62-204.800, F.A.C.]

COMPLIANCE AND PERFORMANCE TEST METHODS FOR OPACITY, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.9. To determine compliance with the opacity limits under 40 CFR 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under 40 CFR 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

a. The owner or operator shall use data from the Contnuous Opacity Montoring System (COMS) to determine compliance in accordance with the procedures in 40 CFR 60.11(e)(5).

b. Alternative test methods for visible emissions shall be EPA Reference Method No. 9 and the procedures in 40 CFR 60.11.

[40 CFR 60.46b(d)(7), 40 CFR 60.11(e)(5), Rule 62-204.800, F.A.C., Applicant's Request]

COMPLIANCE AND PERFORMANCE TEST METHODS FOR SULFUR DIOXIDE, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.10. a. The SO_2 emission standards in 40 CFR 60.42b apply at all times.

b. The owner or operator of an affected facility that only combusts ULSD, NG, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of 40 CFR 60.45b if the owner or operator obtains fuel receipts (see Emission Monitoring SO_2) as described in 40 CFR 60.49b(r).

[40 CFR 60.45b(a) and (j), and Rule 62-204.800, F.A.C.]

EMISSION MONITORING FOR NITROGEN OXIDES, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.11. The owner or operator of an affected facility subject to a NO_x standard under 40 CFR 60.44b shall comply with the following:

a. Install, calibrate, maintain, and operate CEMS for measuring NO_x and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system

b. The required CEMS shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

c. The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by 40 CFR 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall

be used to calculate the average emission rates under 40 CFR 60.44b. The 1-hour averages shall be calculated using the data points required under 40 CFR 60.13(h)(2).

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) Reserved

(2) For affected facilities combusting ULSD or NG, the span value for NO_x is determined using one of the following procedures:

(i) Except as provided under paragraph (d)(2)(ii) of this section, NO_x span values shall be determined as follows:

Fuel	Span values for NO_X (ppm)
NG	500.
ULSD	500.
Mixtures	500 (x + y)

Where:

x = Fraction of total heat input derived from NG;

y = Fraction of total heat input derived from oil

(ii) As an alternative to meeting the requirements of paragraph (d)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_x span values determined according to 40 CFR 75, Appendix A, section 2.1.2.

e. All span values computed under paragraph (d)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (d)(2)(ii) of this section shall be rounded off according to 40 CFR 75, Appendix A, section 2.1.2.

f. When NO_Xemission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

g. The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, NG, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

Comply with the provisions of 40 CFR 60.48b(b), (c), (d), (e)(2), (e)(3), and (f).

[40 CFR 60.48b(b), (c), (d), (e)(2), (e)(3), (f) and (g), Rule 62-204.800, F.A.C.]

EMISSION MONITORING FOR OPACITY, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.12. The owner or operator of an affected facility subject to the opacity standard under 40 CFR 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

[40 CFR 60. 48b(a), Rule 62-204.800, F.A.C.]

EMISSION MONITORING FOR SULFUR DIOXIDE, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.13. The owner or operator of an affected facility that combusts ULSD is not subject to the emission monitoring requirements under 40 CFR 60.47b(a) if the owner or operator maintains fuel records as described in 40 CFR 60.49b(r).

[40 CFR 60.47b(f), Rule 62-204.800, F.A.C.]

NOTIFICATION, RECORDKEEPING AND REPORTING REQUIREMENTS, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.14. a. The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

b. The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_x emission limits under 40 CFR 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS and COMS using the applicable performance specifications in 40 CFR 60, Appendix B.

c. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, ULSD, residual oil, NG, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

d. For an affected facility subject to the opacity standard in 40 CFR 60.43b, the owner or operator shall maintain records of opacity.

e. The owner or operator of an affected facility subject to the NO_x standards under 40 CFR 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_x emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured ;

(3) The 30-day average NO_x emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_xemission rates are in excess of the NO_x emissions standards under 40 CFR 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

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

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 60, Appendix F, Procedure 1.

f. The owner or operator of any affected facility in any category listed in 40 CFR 60.7(f) is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in 40 CFR 60.43b(f) or to the operating parameter monitoring requirements in 40 CFR 60.13(i)(1).

(2) Any affected facility that is subject to the NO_x standard of 40 CFR 60.44b, and that:

(i) Combusts NG, ULSD, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_x emissions on a continuous basis under 40 CFR 60.48b(g)(1).

(3) For the purpose of 40 CFR 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under 40 CFR 60.43b(f).

(4) For purposes of 40 CFR 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under 40 CFR 60.46b(e), that exceeds the applicable emission limits in 40 CFR 60.44b.

g. The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under 40 CFR 60.48(b) shall submit reports containing the information recorded under paragraph (e) of this section.

h. The owner or operator of any affected facility subject to the SO_2 standards under 40 CFR 60.42b shall submit reports.

i. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 5 years following the date of such record.

j. The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in 40 CFR 60.42b shall:

The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, NG, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in 40 CFR 60.42b(j) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of NG as defined in 40 CFR 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, NG, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period.

Note: For purposes of fuel based compliance reporting "PDF" combusted in Boiler No. 1 is not regulated for the pollutant sulfur dioxide under 40 CFR Subpart Db requirements and therefore does not need to be reported in the aforementioned report.

k. The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required by 40 CFR 60.49b (h), (i), (j), (k) or (l). The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format,

the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

l. The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. Unless otherwise required by rule, order, or permit each 6 month period shall run as follows: JAN through JUN AND JUL through DEC.

m. A notification of the date construction of an affected facility (emission unit) is commenced postmarked no later than 30 days after such date.

n. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Department may request additional relevant information subsequent to this notice.

o. A notification of the date upon which demonstration of the continuous monitoring system (COMS and CEMS) performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

p. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5). This notification shall be postmarked not less than 30 days prior to the date of the performance test.

q. Any owner or operator subject to the provisions of this part 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.

r. Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable 40 CFR 60 Subparts) and/or summary report form (see paragraph (d) of 40 CFR 60.7) to the Department semiannually, except when; more frequent reporting is specifically required by an applicable subpart; or the Department, 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 six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §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.

s. The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Department. 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 Department.

(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.

t. Reporting required more frequently than semi-annually may be reduced in accordance with the requirements of 40 CFR 60.7(e).

u. Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, 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; and 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, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition

system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under 40 CFR 60.7(f), the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required under 40 CFR 60.7(f), if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

[40 CFR 60.7, 40 CFR 60. 49b(a), (b), {(d)(1)}, (f), (g), (h), (i), (j), (o), (r), (v), and (w), Rule 62-204.800, F.A.C.]

B. Boiler No. 4

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
004	Boiler No. 4 fired by NG with a maximum design rate of 97.0 MMBtu per hour heat input. This emissions unit is subject to regulation under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources. A Best Available Control Technology (BACT) determination is part of the review required by this rule - BACT Determination dated November 5, 2003. The emission unit is also subject to the requirements of Jacksonville Environmental Protection Board Rules 2.301 - Stationary Sources General Requirements, 2.401 - Stationary Sources Preconstruction Review, 2.1001 - Stationary Sources Emission Standards, and 1.1101 - Stationary Sources Emission Monitoring. Additional restrictions have been added in Section 4 regarding PSD.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

B.1. **Permitted Capacity.** The maximum heat input rate for this emissions unit shall not exceed 97.0 MMBtu/hr.

[Rule 62-210.200(PTE), F.A.C.; JEPB Rule 2.301, Construction Permit No. 0310039-009-AC]

OPERATING REQUIREMENTS

B.2. See title V Air Operation Permit 0310039-012-AV for operation conditions and restrictions. Upon commencement of compliance testing requirements or 180 days after start-up of the No. 1 Boiler (whichever comes first) Boiler No. 4 shall be shut down and permanently removed from service.

[Rule 62-212.300, F.A.C.]

C. Boiler No. 5

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
005	Boiler No. 5 fired by NG, ULSD, or PDF, or any combinations of the fuels with a maximum design rate of 93.0 MMBtu per hour heat input. This emissions unit is subject to regulation under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources. A Best Available Control Technology (BACT) determination is part of the review required by this rule - BACT Determination dated November 5, 2003. The emission unit is also subject to the requirements of Jacksonville Environmental Protection Board Rules 2.301 - Stationary Sources General Requirements, 2.401 - Stationary Sources Preconstruction Review, 2.1001 - Stationary Sources Emission Standards, and 1.1101 - Stationary Sources Emission Monitoring. Additional restrictions have been added in Section 4 regarding PSD.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

C.1. **Permitted Capacity.** The maximum heat input rate for this emissions unit shall not exceed 93.0 MMBtu/hr.

[Rule 62-210.200(PTE), F.A.C.; JEPB Rule 2.301, Construction Permit No. 0310039-009-AC]

OPERATING REQUIREMENTS

C.2. See title V Air Operation Permit 0310039-012-AV for operation conditions and restrictions. Upon commencement of compliance testing requirements or 180 days after start-up of the No. 1 Boiler (whichever comes first) Boiler No. 5 shall be shut down and permanently removed from service.

[Rule 62-212.300, F.A.C.]

D. Boiler No. 6

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
006	Boiler No. 6 fired by NG, ULSD, PDF, or any combinations of the fuels with a maximum design rate of 117.0 MMBtu per hour heat input. This emissions unit is subject to regulation under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources. A Best Available Control Technology (BACT) determination is part of the review required by this rule - BACT Determination dated November 5, 2003. The emission unit is also subject to the requirements of Jacksonville Environmental Protection Board Rules 2.301 - Stationary Sources General Requirements, 2.401 - Stationary Sources Preconstruction Review, 2.1001 - Stationary Sources Emission Standards, and 1.1101 - Stationary Sources Emission Monitoring. Additional restrictions have been added in Section 4 regarding PSD.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

D.1. **Permitted Capacity.** The maximum heat input rate for this emissions unit shall not exceed 117.0 MMBtu/hr.

[Rule 62-210.200(PTE), F.A.C.; JEPB Rule 2.301, Construction Permit No. 0310039-009-AC]

OPERATING REQUIREMENTS

D.2. See Title V Air Operation Permit 0310039-012-AV for operation conditions and restrictions. Upon commencement of compliance testing requirements or 180 days after start-up of the No. 1 Boiler (whichever comes first) Boiler No. 6 shall be subject to the following requirements.

[Rule 62-212.300, F.A.C.]

D.3. **Methods of Operation**. This emissions unit may be fired with either NG, ULSD, PDF, or a blend of NG with PDF. At no time shall the firing of the fuels exceed the 117.0 MMBtu/hr heat input to the Boiler. Vapors from the vapor collection system may also be incinerated in this emissions unit.

Alternative Methods of Operation are described below:

Alternative Method	Fuel Options	Maximum Operating Rate
1	NG	117,009 Cf/hr
2	ULSD	830 Gal/hr
3	NG/PDF	---
4	PDF	1015.6

[Rules 62-4.160(2); 62-210.200(PTE), F.A.C.; Rule 62-213.410, F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; JEPB Rule 2.501; Construction Permit No. 0310039-013-AC]

D.4. Hours of Operation. The hours of operation of Boiler No. 6 shall be limited to 3650 hours per year. The hours of operation shall be recorded.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; Construction Permit No. 0310039-013-AC]

Emission Limitations and Performance 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.}

D.5. Particulate Matter Emissions. Particulate Matter (PM) Emissions shall be limited by the firing of the fuels stated in **Condition D.3.**
[BACT Determination dated November 5, 2003, Rule 62-212.300, F.A.C.]

D.6. Sulfur Dioxide Emissions. Sulfur Dioxide Emissions shall be limited to the sulfur content in the fuels stated in **Condition D.7.** and no more than 850 TPY.

{Permitting Note: Emission Cap established during County/State petition for SO_2 redesignation}

[Rule 62-296.406(3), F.A.C.; JEPB Rule 2.1001; BACT Determination dated November 5, 2003; Operation Permit No. AO16-169132; Construction Permit No. 0310039-013-AC]

D.7. Sulfur Content - Fuels. The maximum sulfur content of the fuels allowed to be fired in this emissions unit are listed below and shall not be exceeded:

A. Fuel Type	*B. Maximum Sulfur Content*
NG	-----
ULSD	0.05 wt. %
PDF	0.5 wt%

[BACT Determination dated 11/05/03; JEPB Rule 2.1001; Construction Permit No. 0310039-013-AC]

D.8. **Visible Emissions.** Visible Emissions shall not exceed 20% Opacity, except for one six-minute period per hour during which opacity shall not exceed 27 percent.
[Rule 62-296.406(1),F.A.C.; JEPB Rule 2.1001; Construction Permit No. 0310039-013-AC]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.9. **Compliance Testing- Sulfur Dioxide.** In lieu of an annual compliance stack test for sulfur dioxide emissions, the Permittee shall comply with the fuel sulfur content restrictions stated in **Condition No. D.7.**

The permittee shall conduct sulfur dioxide compliance test using EPA Method 6, upon Department request in accordance with the requirements of **Condition No. D.14.**
[Construction Permit No. 0310039-009-AC]

D.10. **Compliance Testing-** Particulate Matter Emissions shall be limited by the firing of the fuels stated in **Condition D.3.**

[0310039-013-AC]

D.11. **Compliance Testing- Visible Emissions.** The test method for visible emissions for this emissions unit shall be EPA Method 9 as stated in Rule 62-297.401(9)(c) F.A.C. This compliance test shall be conducted if the Boiler (or a combination of Boiler Nos. 6 and 7) operates 400 hours or more per calendar year.
[JEPB Rule 2.1101; Construction Permit No. 0310039-013-AC]

D.12. **Sulfur Content.** The permittee shall comply with the following:

- Each delivery of ULSD to be fired in the No. 6 Boiler shall be analyzed for the sulfur content prior to use. If ULSD is added to the tank a new analysis is required. Fuel oil supplier analysis may be substituted for the testing provided the analysis is conducted in accordance

with established and appropriate ASTM methods listed below. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

- Each batch of the PDF used in the No. 6 Boiler shall be analyzed for its sulfur content. The sulfur content in the PDF fired shall be determined by the latest sampling and analytical procedures specified in ASTM D-129 or ASTM D-2622 procedures. The laboratory shall certify results. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

[Construction Permit No. 0310039-013-AC]

D.13. **SO_2 Recordkeeping.** The Permittee shall maintain a record of the fuel oil sulfur content analysis results stated in **Condition No. D.13.** for a period of 5 years.

[Rule 213.440(1)b., F.A.C., JEPB Rule 2.501; Construction Permit No. 0310039-013-AC]

Common Conditions - F.A.C. Test Requirements

D14. This emissions unit is also subject to Prevention of Significant Deterioration Requirements in Section 4 and applicable F.A.C. Test Requirements in Section 5.

E. Boiler No. 7

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
011	Boiler No. 7 fired by NG, Ultra Low Sulfur Distillate fuel oil, process derived fuel, or any combinations of the fuels with a maximum design rate of 49.0 MMBtu per hour heat input. This emissions unit is subject to regulation under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources. A Best Available Control Technology (BACT) determination is part of the review required by this rule - BACT Determination dated November 5, 2003. The emission unit is also subject to the requirements of Jacksonville Environmental Protection Board Rules 2.301 - Stationary Sources General Requirements, 2.401 - Stationary Sources Preconstruction Review, 2.1001 - Stationary Sources Emission Standards, and 1.1101 - Stationary Sources Emission Monitoring. Additional restrictions have been added in Section 4 regarding PSD.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

E.1. **Permitted Capacity.** The maximum heat input rate for this emissions unit shall not exceed 49.0 MMBtu/hr.

[Rule 62-210.200(PTE), F.A.C.; JEPB Rule 2.301, Construction Permit No. 0310039-013-AC]

OPERATING REQUIREMENTS

E.2. See Title V Air Operation Permit 0310039-012-AV for operation conditions and restrictions. Upon commencement of compliance testing requirements or 180 days after start-up of the No. 1 Boiler (whichever comes first) Boiler No. 7 shall be subject to the following requirements.

[Rule 62-212.300, F.A.C.]

E.3. **Methods of Operation**. This emissions unit may be fired with either NG, ULSD, PDF, or a blend of NG with PDF. At no time shall the firing of the fuels exceed the 49.0 MMBtu/hr heat input to the Boiler. Vapors from the vapor collection system may also be incinerated in this emissions unit.

Alternative Methods of Operation are described below:

Alternative Method	Fuel Options	Maximum Operating Rate
1	NG	46,800 CF/Hr
2	ULSD	348 Gal/hr
3	NG/PDF	---
4	PDF	425 Gal/hr

[Rules 62-4.160(2); 62-210.200(PTE), F.A.C.; Rule 62-213.410, F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; JEPB Rule 2.501; Construction Permit No. 0310039-009-AC]

E.4. **Hours of Operation.** The hours of operation shall be limited to 3650 hours per year. The hours of operation shall be recorded.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; Construction Permit No. 0310039-013-AC]

Emission Limitations and Performance 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.}

E.5. **Particulate Matter Emissions.** Particulate Matter (PM) Emissions shall be limited by the firing of the fuels stated in **Condition E.3.**
[BACT Determination dated November 5, 2003, Rule 62-212.300, F.A.C.]

E.6. **Sulfur Dioxide Emissions.** Sulfur Dioxide Emissions shall be limited to the sulfur content in the fuels stated in **Condition E.7.** and no more than 139.3 TPY.

{Permitting Note: Emission Cap established during County/State petition for SO_2 redesignation}

[Rule 62-296.406(3), F.A.C.; JEPB Rule 2.1001; BACT Determination dated November 5, 2003; Operation Permit No. AO16-169132; Construction Permit No. 0310039-009-AC]

E.7. **Sulfur Content - Fuels.** The maximum sulfur content of the fuels allowed to be fired in this emissions unit are listed below and shall not be exceeded:

E. Boiler No. 7

C. Fuel Type	*D. Maximum Sulfur Content*
NG	-----
ULSD	0.05 wt. %
PDF	0.5 wt%

[BACT Determination dated 11/05/03; JEPB Rule 2.1001; Construction Permit No. 0310039-009-AC]

E.8. **Visible Emissions.** Visible Emissions shall not exceed 20% Opacity, except for one six-minute period per hour during which opacity shall not exceed 27 percent.
[Rule 62-296.406(1),F.A.C.; JEPB Rule 2.1001; Construction Permit No. 0310039-013-AC]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.9. **Compliance Testing- Sulfur Dioxide.** In lieu of an annual compliance stack test for sulfur dioxide emissions, the Permittee shall comply with the fuel sulfur content restrictions stated in **Condition No. E.7.**

The permittee shall conduct sulfur dioxide compliance testing using EPA Method 6, upon Department request, in accordance with the requirements of **Condition No. E.14.**
[Construction Permit No. 0310039-013-AC]

E.10. **Compliance Testing-** Particulate Matter Emissions shall be limited by the firing of the fuels stated in **Condition E.3.**

[Construction Permit No. 031009-013-AC]

E.11. **Compliance Testing- Visible Emissions.** The test method for visible emissions for this emissions unit shall be EPA Method 9 as stated in Rule 62-297.401(9)(c) F.A.C. This compliance test shall be conducted if the Boiler (or a combination of Boiler Nos. 6 and 7) operates 400 hours or more per calendar year.
[JEPB Rule 2.1101; Construction Permit No. 0310039-013-AC]

E.12. **Sulfur Content.** The permittee shall comply with the following:

- Each delivery of ULSD to be fired in the No. 7 Boiler shall be analyzed for the sulfur content prior to use. If ULSD is added to the tank a new analysis is required. Fuel oil supplier analysis may be substituted for the testing provided the analysis is conducted in accordance with established and appropriate ASTM methods listed below. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

- Each batch of the PDF used in the No. 6 Boiler shall be analyzed for its sulfur content. The sulfur content in the PDF fired shall be determined by the latest sampling and analytical procedures specified in ASTM D-129 or ASTM D-2622 procedures. The laboratory shall certify results. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

[Construction Permit No. 0310039-013-AC]

E13. **SO_2 Recordkeeping.** The Permittee shall maintain a record of the fuel oil sulfur content analysis results stated in **Condition No. E.13.** for a period of 5 years.

[Rule 213.440(1)b., F.A.C., JEPB Rule 2.501; Construction Permit No. 0310039-013-AC]

Common Conditions - F.A.C. Test Requirements

E.14. This emissions unit is also subject to Prevention of Significant Deterioration Requirements in Section 4 and applicable F.A.C. Test Requirements in Section 5.

RECORDKEEPING AND REPORTING REQUIREMENTS

A.1. Actual Emissions Reporting: This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and the project avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Therefore, pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions.

a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; 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 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.

b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:

1) The name, address and telephone number of the owner or operator of the major stationary source;
2) The annual emissions as calculated pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;
3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and
4) Any other information that the owner or operator wishes to include in the report.

c. 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.

d. For this project, the following are the estimated baseline actual emissions: 26.4 tons/year of carbon monoxide (CO); 94 tons/year of oxides of nitrogen (NO_X); 824 tons/year of sulfur dioxide (SO_2); 25.9/year of particulate matter (PM), 25.9 tons/year particulate matter of 10 microns or less (PM_{10}); and 2.7 tons/year of volatile organic compounds (VOC).

e. The permittee shall compute and report annual emissions in accordance with Rule 62-210.370(2), F.A.C. as provide by Appendix C of this permit. For this project, the permittee shall use the following methods in reporting the actual annual emissions for the Steam Repowering Project (identified as Emission Unit Nos. 032, 006, and 011):

1) Emission Unit No. 032 (Boiler No. 1)

   i. The permittee shall use data collected from the CEMS to determine and report the actual annual emissions of NO_X for the No. 1 Boiler.
   ii. The permittee shall use the data collected from the required stack tests to determine and report the actual annual emissions of PM/PM_{10}. The permittee shall follow the stack test methods, test procedures and test frequencies specified in this permit. To determine compliance the test results must be at or below the PM limit listed in the Performance Restricions section of the permit. To calculate the annual PM emissions the the activity factor for the calendar year shall be multiplied by the Performance Restriction limit to determine the annual emissions.
   iii. The permittee shall use stoichometric data calculations to determine SO_2 emissions. Total pounds of sulfur received by the facility during the reporting period shall be the basis for determining the annual SO_2 emissions. Sulfur which may be adequately accounted that is not combusted may be deducted from the total sulfur used for the calculations.
   iv. Unless otherwise approved by the Department, the permittee shall use the same emissions factors for reporting the actual annual emissions of CO and VOC as used in the application to establish baseline emissions multiplied by the calendar year activity factor.

2) Emission Unit Nos. 006 and 011 (Boiler Nos. 6 and 7 respectively)

   i. The permittee shall use the data collected from the required stack tests (Boiler No. 1 or Boiler Nos. 6/7 if required) to determine and report the actual annual emissions of PM/PM_{10}. The permittee shall follow the stack test methods, test procedures and test frequencies specified in this permit. To determine compliance the test results must be at or below the PM limit listed in the Performance Restrictions section of the permit. To calculate the annual PM emissions the the activity factor for the calendar year shall be multiplied by the Performance Restriction limit to determine the annual emissions.
   ii. The permittee shall use stoichometric data calculations to determine SO_2 emissions. Total pounds of sulfur received by the facility during the reporting period shall be the basis for determining the annual SO_2 emissions. Sulfur which may be adequately accounted, that is not combusted, may be deducted from the total sulfur used for the calculations.
   iii. Unless otherwise approved by the Department, the permittee shall use the same emissions factors for reporting the actual annual emissions of CO and VOC as used in the application to establish baseline emissions multiplied by the calendar year activity factor.
   iv. The emission factors listed in the Performance Restrictions shall be used to calculate the annual NOx emissions from the operation of Boiler Nos. 6/7. The emission factor shall be multiplied times the activity factor for each fuel fired in

the Boiler(s) for the calendar year. To determine compliance (if stack testing is required) the test results must be at or below the NOx limit listed in the Performance Restrictions section of the permit.

3) As defined in Rule 62-210.370(2), F.A.C., the permittee shall use a more accurate methodology if it becomes available.

[Application No. 0310039-013-AC; Rules 62-212.300(1)(e), and 62-210.370, F.A.C.]

A.2. Recordkeeping: The permittee shall maintain records as follows:

a. The quantity and sulfur content by weight of each shipment received of crude sulphate turpentine. These records shall be provided to the Department upon request.

b. Calculations on a monthly basis of sulfur dioxide emissions based upon the methodology listed in Section 4, Recordkeeping and Reporting Requirements, A.1.,e.,1), iii. above.

c. Records of each fuel burned in each Boiler as follows:

1) Quantity and number of hours on a monthly basis
2) Analysis as follows:
   i. *Fuel oil for each shipment received for sulfur, nitrogen, ash percent by weight
   ii. Process derived fuel (PDF) for each batch produced for sulfur, nitorgen, and ash percent by weight
   iii. *NG for sulfur and nitrogen content percent by weight

*Fuel oil and NG fuel supplier records may be used provided analytical methods are identified and are acceptable to the Department.

TESTING AND ANALYSIS REQUIREMENTS

A.3. Stack Testing (Boiler No. 1) while firing a normal mixture of PDF and NG. Record the quantity and type of each fuel fired during the test.

a. PM on an annual basis (each calendar year) using EPA RM 5
b. SO_2, upon request, using EPA RM 6 or other method approved by the Department
c. NO_x, Oxides of Nitrogen (NOx) shall be continuously measured on Boiler no. 1 through the use of a Continuous Emission Monitoring System (CEMS). The CEMS shall meet all requirements of the NOx CEMS required by 40 CFR 60, Subpart Db.
d. CO, upon request, using EPA RM 10 or other method approved by the Department
e. VOC, upon request, using EPA RM 25 or other method approved by the Department

A.4. Stack Testing (Boiler Nos. 6/7) while firing a normal mixture of PDF and NG. Record the quantity and type of each fuel fired during the test.

a. PM on an annual basis (each calendar year) using EPA RM 5 if the Boilers combined operate more than 400 Boiler operating hours per calendar year, otherwise upon request
b. SO_2, upon request, using EPA RM 6 or other method approved by the Department
c. If Boiler Nos. 6 and/or 7 operate more than 400 Boiler operating hours per calendar year a NOx test is required within 90 days of achieving the 400 hour operation level. Testing shall be conducted on Boiler no. 6 in accordance EPA RM 7E. Testing shall be conducted at 90% to 100% of the maximum heat input of the Boiler or at the highest rate (or higher) that the Boiler operated during the past 12 months. The typical fuel mixture shall be used during the three run test. Otherwise testing shall be upon request.
d. CO, upon request, using EPA RM 10 or other method approved by the Department
e. VOC, upon request, using EPA RM 25 or other method approved by the Department

A.5. *Fuel Analysis for sulfur, nitrogen, and ash for liquid fossil fuels and sulfur and nitrogen for gaseous fossil fuels shall be conducted in accordance with the ASTM Method applicable to that fuel as described in 40 CFR 60.17.

A.6. Each batch of PDF produced shall be analyzed for the sulfur content (% by weight), and the ash content (% by weight). Applicable ASTM Methods shall be used as approved in 40 CFR 60. 17. Alternate methods may be approved in writing by the Department.

*Fuel oil and NG fuel supplier records may be used provided analytical methods are identified and are acceptable to the Department.
[Rules 62-212.300(1)(e), 62-210.370, and 62-4.070, F.A.C.]

PERFORMANCE RESTRICTIONS AND REQUIREMENTS

A.7. The following performance restrictions were used in the calculations to determine potential to emit and expected actual emissions during the permit review process. These restrictions coupled with testing and analysis provide reasonable assurance that compliance with applicable rules is maintained.

a. PDF fuel combustion shall be limited to 4.5 million gallons per 12 month rolling total. The sulfur content of PDF shall not exceed 0.50% by weight.
b. PM emissions shall not exceed 0.131 lbs per MMBtu heat input of PDF
c. NO_x emissions from the combustion of PDF in Boiler Nos. 6/7 shall not exceed 0.289 lbs per MMBtu heat input
d. NO_x emissions from the combustion of NG in Boiler Nos. 6/7 shall not exceed 0.265 lbs per MMBtu heat input
e. NO_x emissions from Boiler No. 1 shall not exceed 0.20 lbs per MMBtu heat input

A.8. The permittee shall measure the fuel flow rates to each boiler. The fuel flow measurement device(s) shall be accurate to within plus or minus 5 percent accuracy. Calibration of the device(s) shall be conducted in accordance with manufacturers' instructions on a frquency

recommended by the manufacturer. Monthly records of the fuel flow shall be compiled and maintained and made available to the Department upon request.

A.9. Boiler Nos. 6/7shall be limited to the firing of NG under normal operating conditions. If Boiler No. 1 is not operational for an extended period of time and the permittee is limited in adequate storage capacity for PDF then authorization to combust PDF in the Boiler Nos. 6/7 is granted. In no case shall Boiler Nos. 6/7 combust in excess of 3.285 million gallons of PDF per 12 month rolling total or an equivalent combination (measured as Btu input) of PDF and NG. Boiler Nos. 6/7 shall not exceed an average firing rate (combined) of 123 million Btu per hour during the operational period. Boiler No. 1 shall not operate simultaneously with Boiler Nos. 6/7 except during transitional periods when Boiler No. 1 is starting up or shutting down.