Friday, Barbara

From: Harvey, Mary
Sent: Tuesday, April 03, 2007 9:42 AM
To: Adams, Patty
Subject: FW: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

From: Neil Smith [mailto:nsmith@ussugar.com]
Sent: Tuesday, April 03, 2007 9:39 AM
To: Harvey, Mary
Subject: RE: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, March 30, 2007 2:20 PM
To: Neil Smith; Peter Briggs; Don Griffin
Cc: Koerner, Jeff; Adams, Patty
Subject: FW: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

From: Harvey, Mary
Sent: Friday, March 30, 2007 2:18 PM
To: 'DBuff@Golder.com'; Blackburn, Ron; 'Mr. Gregg Worley, EPA Region 4'; 'dee_morse@nps.gov'
Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Harvey, Mary
Sent: Tuesday, April 03, 2007 8:43 AM
To: Adams, Patty
Subject: FW: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Monday, April 02, 2007 4:56 PM
To: Harvey, Mary
Subject: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

Return Receipt

Your document:	United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL
was received by:	Dee Morse/DENVER/NPS
at:	04/02/2007 02:55:52 PM

Friday, Barbara

From: Harvey, Mary
Sent: Monday, April 02, 2007 10:09 AM
To: Adams, Patty
Subject: FW: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

From: Buff, Dave [mailto:DBuff@GOLDER.com]
Sent: Friday, March 30, 2007 5:48 PM
To: undisclosed-recipients
Subject: Read: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

Your message

To: DBuff@GOLDER.com
Subject:

was read on 3/30/2007 5:48 PM.

Friday, Barbara

From: Harvey, Mary
Sent: Friday, March 30, 2007 3:12 PM
To: Adams, Patty
Subject: FW: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

From: Blackburn, Ron
Sent: Friday, March 30, 2007 2:38 PM
To: Harvey, Mary
Subject: Read: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

Your message

To: 'DBuff@Golder.com'; Blackburn, Ron; 'Mr. Gregg Worley, EPA Region 4'; 'dee_morse@nps.gov'
Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL
Sent: 3/30/2007 2:18 PM

was read on 3/30/2007 2:38 PM.

Friday, Barbara

From: Harvey, Mary

Sent: Friday, March 30, 2007 2:18 PM

To: 'DBuff@Golder.com'; Blackburn, Ron; 'Mr. Gregg Worley, EPA Region 4'; 'dee_morse@nps.gov'

Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria

Subject: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

Attachments: 0510003.037.AC.F_pdf.zip

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Harvey, Mary
Sent: Friday, March 30, 2007 2:20 PM
To: 'NSMITH@USSUGAR.COM'; 'Peter Briggs'; 'DGRIFFIN@USSUGAR.COM'
Cc: Koerner, Jeff; Adams, Patty
Subject: FW: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL
Attachments: PSD-FL-333C Boiler 8 - Appendix - Facility #0510003-037-AC - FINAL.PDF; PSD-FL-333C Boiler 8 - Final Determination - Facility #0510003-037_AC-FINAL.PDF; PSD-FL-333C Boiler 8 - Final Notice - Facility #051003-037-AC-FINAL.PDF; PSD-FL-333C Boiler 8 - Final Permit - Facility #051003-037-AC- FINAL.PDF; Signed Documents for Facility ID #0510003-037-AC-FINAL.pdf

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From: Harvey, Mary
Sent: Friday, March 30, 2007 2:18 PM
To: 'DBuff@Golder.com'; Blackburn, Ron; 'Mr. Gregg Worley, EPA Region 4'; 'dee_morse@nps.gov'
Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: United States Sugar Corporation - Facility ID #0510003-037-AC-FINAL

Dear Sir/Madam:

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The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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Thank you,

DEP, Bureau of Air Regulation

Memorandum

Florida Department of Environmental Protection

TO:	Joseph Kahn, Division of Air Resource Management
THRU:	Trina Vielhauer, Bureau of Air Regulation TV
FROM:	Jeff Koerner, Air Permitting North JK
DATE:	March 29, 2007
SUBJECT:	Air Permit No. PSD-FL-333C Project No. 0510003-037-AC Clewiston Sugar Mill and Refinery Heat Input Increase for Boiler 8

The final permit for this project is attached for your approval and signature. The permit authorizes an increase in the maximum heat input rate for the newly constructed Boiler 8 and modifications to the biomass handling system. These units are installed at the Clewiston Sugar Mill and Refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. I recommend your approval of the attached final permit for this project.

Attachments

JK/tlv/jfk

PERMITTEE

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Air Permitting North Program
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery

This permitting action is a revision of the air construction permit to specifically address the following items: increased heat input and steaming rates for Boiler 8; clarification of startup procedures for Boiler 8; and modification of the biomass fuel handling system. These existing units are installed at Clewiston Sugar Mill and Refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on September 1, 2006. The applicant provided comments on the draft permit regarding the existing bagacillo cyclone on the biomass handling system. The Department agreed to the changes and issued a revised draft permit on February 6, 2007. The applicant published the Public Notice of Intent to Issue in The Clewiston News on February 22, 2007. The applicant provided proof of publication on March 12, 2007. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

No comments on the draft permit were received from the public or the Department's South District Office. The following summarizes the applicant's comments and the Department's response.

1. *Placard Page*: Recognize that the authorized representative is now Mr. Neil Smith, Vice President of Sugar Processing Operations. *Response*: The correction is made to the final permit.
2. *Page 16 of 16, Specific Condition 2*: For the biomass handling system, change text from, "To minimize fugitive particulate matter, biomass conveyors shall be <u>covered</u> ~~enclosed~~ and new landing zones shall be installed on conveyor transfer points. <u>The existing dust collectors for the biomass handling system will be removed</u>. The conveyor system will now be completely <u>covered or</u> enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill." This more accurately reflects the text used in the Technical Evaluation and Preliminary Determination. *Response*: The clarification is made to the final permit.

CONCLUSION

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

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

PERMITTEE:

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440
Authorized Representative:
Mr. Neil Smith, V.P. of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Facility ID No. 0510003
Permit Expires: March 31, 2008

FACILITY AND LOCATION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery.

STATEMENT OF BASIS

Boiler 8 was recently constructed under Permit No. PSD-FL-333, as modified. This permitting action is a revision of the air construction permit to specifically address the following items: increases in the heat input and steaming rates; clarification of startup procedures; and modification of the biomass fuel handling system. The revised 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 perform the proposed work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

Trina L Vielhauer for — 3/30/07

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Authorized Representative:
Mr. Neil Smith, V.P. of Sugar Processing Operations

Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler 8 Heat Input Revision

Enclosed is final Air Permit No. 0510003-037-AC, which authorizes a revision of the air construction permit to specifically address the following items: increases in the heat input and steaming rates; clarification of startup procedures; and modification of the biomass fuel handling system. The existing equipment is installed at the Clewiston Sugar Mill and Refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

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.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit) was sent by electronic mail with return receipt requested to the persons listed below.

Mr. Neil Smith, U.S. Sugar (nsmith@ussugar.com)
Mr. Peter Briggs, U.S. Sugar (pbriggs@ussugar.com)
Mr. Don Griffin, U.S. Sugar (dgriffin@ussugar.com)
Mr. David Buff, Golder Associates (dbuff@golder.com)
Mr. Ron Blackburn, SD Office (ron.blackburn@dep.state.fl.us)
Mr. Gregg Worley, EPA Region 4 (worley.gregg@epa.gov)
Mr. Dee Morse (dee_morse@nps.gov)

Clerk Stamp

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

Mary L Harvey (Clerk) 3/30/07 (Date)

PROJECT DESCRIPTION

Boiler 8 (EU-028) is a new spreader-stoker boiler with a maximum heat input rate of 1185 MMBtu per hour. It will fire bagasse as the primary fuel and wood chips as an alternate or supplemental fuel. Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Air pollution control equipment includes a cyclone/electrostatic precipitator (ESP) combination to remove particulate matter and a selective non-catalytic reduction system (SNCR) to reduce nitrogen oxides. Good combustion design and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Low sulfur fuels (i.e., bagasse, wood chips, and distillate oil) will be used to minimize potential emissions of sulfuric acid mist and sulfur dioxide. Monitoring equipment will continuously monitor and record emissions of carbon monoxide and nitrogen oxides. To minimize fugitive particulate matter from the biomass handling system (EU-027), biomass conveyors will be enclosed and new landing zones installed on conveyor transfer points.

REGULATORY CLASSIFICATION

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

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

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major facility as defined in Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the applicable New Source Performance Standards in Subpart Db of 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for HAP in Subpart DDDDD of 40 CFR 63.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Formats

Appendix B. General Conditions

Appendix C. Common Requirements

Appendix D. NSPS Provisions

Appendix E. Summary of Final BACT Determinations

Appendix F. Good Combustion and Operating Practices

Appendix G. Quarterly CO and NOx Emissions Report

Appendix H. Shakedown Period

Appendix I. **Incidental Amounts of On-Specification Used Oil with Bagasse**

Appendix J. NESHAP Provisions

RELEVANT DOCUMENTS

The applications, correspondence, and permits related to the following projects are considered relevant documents: original Project No. 0510003-021-AC (PSD-FL-333), revised Project No. 0510003-024-AC (PSD-FL-333A), Project No. 0510003-030-AC (PSD-FL-333B), and Project No. 0510003-037-AC (PSD-FL-333C). Relevant documents are not a part of this permit, but include information specifically related to this permitting action and are on file with the Department.

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of each application shall be submitted to the Compliance Authority.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.
3. Rule Citations: Appendix A of this permit explains the methods used to cite rules, regulations, and permits.
4. General Conditions: The permittee shall comply with the general conditions specified in Appendix B of this permit. [Rule 62-4.160, F.A.C.]
5. Common Requirements: The permittee shall comply with the common regulatory requirements specified in Appendix C of this permit. [Chapters 62-4, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.]
6. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and Title 40 of the Code of Federal Regulations (CFR) adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(12)(a), F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]
8. 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.]
9. Source Obligation: 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. [Rule 62-212.400(12)(b), F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rule 62-4.030 and Chapters 62-210 and 62-212, F.A.C.]

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

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

ID	Emission Unit Description
028	*Description*: Boiler 8 will be a membrane wall boiler with balanced draft stoker, overfire air, rotating feeders, and pneumatic spreaders. It will be designed to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. *Fuels*: The primary fuel will be bagasse (SCC No. 1-02-011-01). Wood chips will be fired as an alternate or supplemental fuel (SCC No. 1-02-009-02). Distillate oil (SCC No. 1-02-005-01) containing no more than 0.05% sulfur by weight will be fired as a restricted alternate fuel for startup and supplemental uses. *Capacity*: The maximum continuous steam production is 575,000 pounds per hour based on a maximum heat input rate of 1077 MMBtu per hour (24-hour averages). *Controls*: Particulate matter is controlled by cyclone collectors followed by an electrostatic precipitator (ESP). Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used to minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. *Stack Parameters*: The stack will be 13.0 feet in diameter (maximum) and 199 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of 315° F and a volumetric flow rate of 395,000 acfm at 5.5% oxygen (270,000 dscfm at 7% oxygen). *CEMS*: Emissions of carbon monoxide and nitrogen oxides will be monitored and recorded by continuous emissions monitoring systems (CEMS).

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions of nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC). Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The final BACT determinations are presented in Appendix E of this permit. Boiler 8 is also subject to the following applicable requirements: Rule 62-296.405, F.A.C. (fossil fuel fired steam generators with more than 250 MMBtu per hour of heat input); Rule 62-296.410, F.A.C. (carbonaceous fuel burning equipment); the federal New Source Performance Standards (NSPS) of Subpart Db (industrial boilers) in 40 CFR 60, which is adopted by reference in Rule 62-204.800(8), F.A.C.; and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) of Subpart DDDDD (industrial boilers) in 40 CFR 63, which is adopted by reference in Rule 62-204.800(11), F.A.C.}

EQUIPMENT

1. Shutdown of Boiler 3: No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of first fire in Boiler 8. Shakedown of the boiler is defined in Appendix H of this permit. During the authorized shakedown period:

   a. Boiler 8 may operate with the other existing boilers to ensure proper integration with the sugar mill and refinery. Any fuel oil fired in Boilers 1, 2, and 3 shall contain no more than 1.6% sulfur by weight.

   b. Boilers 3 and 8 may operate concurrently for no more than 90 individual days during which the combined steam production from Boilers 3 and 8 shall not exceed a daily average of 250,000 pounds per hour. After first fire and shakedown of Boiler 8, Boiler 3 shall be permanently shutdown prior to commencement of commercial operation of Boiler 8 or after completion of the crop season, whichever occurs first. For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September.

No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of the permanent shutdown of Boiler 3 and of beginning commercial operation of Boiler 8. *{Permitting Note: Emissions decreases from the shutdown of Boiler 3 were used in the netting analysis to avoid PSD review of CO emissions for this project. The authorized shakedown period provides a reasonable period to start up the newly designed Boiler 8, test operations, and make necessary adjustments. A limited amount of concurrent operation is allowed because Boiler 8 is replacing Boiler 3 and must be fully tested during the crop season.}* [Design; Rule 62-212.400 (PSD), F.A.C.]

2. Construction of Boiler 8: The permittee is authorized to construct a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at design conditions of 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 633,000 pounds per hour based on a maximum 1-hour heat input rate of 1185 MMBtu per hour. Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse and/or wood chips. Low NOx burners will be used to fire distillate oil as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. Within 90 days of selecting the final design and vendor, the permittee shall submit the final primary design details of the proposed boiler. [Design]

3. Air Pollution Control Equipment: To comply with the standards of this permit, the permittee shall install the following air pollution control equipment.

   a. *Cyclone Collectors*: The permittee shall design, install, operate, and maintain a pre-control device prior to the electrostatic precipitator (ESP) to remove entrained sand and large particles in the flue gas. The purpose of the pre-control device is to prevent excessive equipment wear and overloading of the ESP. Two wet and one dry cyclone collectors are installed in parallel before the induced draft fan.

   b. *ESP*: The permittee shall design, install, operate, and maintain an electrostatic precipitator (ESP) to remove particulate matter from the flue gas exhaust and achieve the particulate matter standards specified in this permit. The ESP shall include an automated rapping system that can adjust rapping frequency and intensity to prevent re-entrainment of fly ash. The ESP shall be on line and functioning properly whenever bagasse and/or wood chips is fired.

   c. *SNCR*: The permittee shall design, install, operate, and maintain a urea-based selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide emissions in the flue gas exhaust and achieve the nitrogen oxides emissions standards specified in this permit. The system shall include automated control of urea injection for at least three injection zones to respond to varying load and flue gas conditions. Urea injection rates and zones will be determined based on parameters such as the current injection rate, furnace temperature profile, fuels, steam load, oxygen level, carbon monoxide level, and nitrogen oxide emissions.

   Within 90 days of selecting the final equipment designs and vendors, the permittee shall submit the final primary design details for the proposed pollution controls. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary fuel, wood chips as an alternate or supplemental fuel, and distillate oil as a restricted alternate fuel for startup and supplemental uses. Bagasse is the fibrous material remaining after sugarcane is milled. Only new No. 2 (or superior) distillate oil containing no more than 0.05% sulfur by weight shall be fired. In addition, incidental amounts of on-specification used oil commingled with bagasse may be fired in Boiler 8 in accordance with the requirements in Appendix I of this permit. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

5. Boiler Capacities and Restrictions: The hours of operation are not restricted (8760 hours/year). The maximum continuous steam production capacity (24-hour average) is 575,000 pounds per hour based on a maximum heat input rate of 1077 MMBtu per hour (24-hour average). The total maximum heat input from the oil burners is 562 MMBtu per hour (4161 gallons/hour). Boiler 8 shall not exceed the following operational levels.

   a. 13,800,000 pounds of steam per day (equivalent to 575,000 pounds of steam per hour and 1077 MMBtu per hour, 24-hour averages);
   b. $3.6135 \times 10^{+09}$ pounds of steam per consecutive 12 months (equivalent to 6,767,100 MMBtu per year);
   c. 99,864 gallons of distillate oil per day (equivalent to 13,488 MMBtu per day); and
   d. 6,073,600 gallons of distillate oil per consecutive 12 months (equivalent to 819,936 MMBtu per year).

   {Permitting Note: The short-term restrictions form the basis of the Air Quality Analysis. The restriction on annual steam production is a surrogate for heat input and allowed the project to avoid PSD applicability for carbon monoxide emissions. The annual oil firing restriction results in an annual capacity factor of 10% or less, which avoids specific requirements in NSPS Subpart Db.} [Design; Rules 62-4.070(3), 62-212.400 (PSD), 62-210.200(PTE), F.A.C.; NSPS Subpart Db]

6. Good Combustion and Operating Practices: The permittee shall follow the good combustion and operating practices identified in Appendix F of this permit. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: See Appendix E of this permit for a summary of the final BACT determinations.}

7. Standards Based on Stack Tests: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The mass emission rates (pounds per hour) are based on the maximum 24-hour heat input rate. Unless otherwise specified, compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

   a. *Ammonia Slip*: As determined by EPA Conditional Test Method CTM-027, ammonia slip shall not exceed 20 ppmvd @ 7% oxygen. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

   b. *Carbon Monoxide (CO)*: To the extent practicable, short term emissions of carbon monoxide shall be controlled by implementing the good combustion and operating practices identified in Appendix F. [Rules 62-4.070(3), F.A.C.]

   c. *Nitrogen Oxides (NOx)*: As determined by EPA Method 7E stack test, NOx emissions shall not exceed 0.14 lb/MMBtu and 150.8 pounds per hour. *{Permitting Note: This standard is an "initial demonstration standard" intended to show the capabilities of the SNCR system as designed. After the initial compliance test, subsequent compliance shall be demonstrated with the long-term CEMS-based standard specified in Condition 8b.}* [Rule 62-212.400 (PSD), F.A.C.]

   d. *Opacity*: As determined by EPA Method 9 observations or COMS, the stack opacity shall not exceed 20% based on a 6-minute average. [Rule 62-212.400 (PSD), F.A.C.]

   e. *Particulate Matter (PM/PM_{10})*: As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.025 lb/MMBtu and 26.9 pounds per hour. [Rule 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

   f. *Sulfur Dioxide (SO_2)*: As determined by EPA Method 6C stack test, SO_2 emissions shall not exceed 0.06 lb/MMBtu and 64.6 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400 (PSD), F.A.C.]

g. *Volatile Organic Compounds (VOC)*: As determined by EPA Methods 18 and 25A stack tests, VOC emissions shall not exceed 0.05 lb/MMBtu and 53.9 pounds per hour measured as propane. For this permit, "VOC" emissions shall be defined as the total hydrocarbons (THC) measured by EPA Method 25A less the sum of the methane and ethane emissions as measured by EPA Method 18 on a concurrent sample. Alternatively, the permittee may elect to assume that all THC are regulated VOC emissions. [Rule 62-212.400 (PSD), F.A.C.]

h. *Hydrogen Chloride (HCl)*: As determined by EPA Method 26 or 26A stack test, HCl emissions shall not exceed 0.02 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7500]

i. *Mercury (Hg)*: As determined by the fuel analysis requirements specified in §63.7521 and Table 6 of Subpart DDDDD in 40 CFR 63, mercury emissions shall not exceed 0.000003 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7521]

8. Standards Based on CEMS: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels and under all load conditions.

   a. *Carbon Monoxide (CO)*:

      1) As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 7% oxygen based on a 30-day rolling average. Carbon monoxide emission levels must be maintained below this work practice standard at all times except during periods of startup, shutdown, malfunction, and when the boiler or process heater is operating at less than 50% of rated capacity. For purposes of calculating data averages, data recorded during the following periods must not be used: periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler is operating at less than 50% of its rated capacity. All the data collected during all other periods must be used in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements. [40 CFR 63.7500(1), 63.7525(a)(6), 63.7540(a)(10) and Table 1 of Subpart DDDDD]

      2) As determined by CEMS data, CO emissions shall not exceed 1285 tons during any consecutive 12 months including periods of startup, shutdown, and malfunction. *{Permitting Note: Compliance with the annual mass emission standard ensures that the project is not subject to PSD preconstruction review for CO emissions.}* [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

   b. *Nitrogen Oxides (NOx)*: As determined by CEMS data, NOx emissions shall not exceed 0.14 lb/MMBtu based on a 30-day rolling average. [Rule 62-212.400 (PSD), F.A.C.]

   {Permitting Note: Appendix H of this permit specifies additional requirements regarding the initial shakedown period and initial demonstration of compliance for the CEMS-based standards.}

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

9. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with the following. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not

release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

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

11. Excess Emissions - Allowed: Unless otherwise specified by this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

12. Excess Emissions – CO, NOx, and Opacity Requirements: As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.

    a. *CO Emissions*: All valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements.

    b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, malfunction, and authorized periods of uncontrolled NOx monitoring may be excluded from the determination of compliance with the 30-day rolling emissions standard, provided:

        1) Best operational practices are used to minimize emissions;

        2) For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional;

        3) For malfunctions, excluded data shall not exceed two hours in any 24-hour period (eight 15-minute CEMS blocks or quadrants of an hour). The permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

        4) For two hours each month, the permittee may operate the boiler without the SNCR system in order to collect uncontrolled NOx emissions data with the CEMS. For purposes of collecting uncontrolled NOx emissions data to adjust the SNCR system, excluded data shall not exceed two, 1-hour values during any calendar month. *{Permitting Note: Based on the final design specifications, uncontrolled NOx emissions are expected to be 0.30 lb/MMBtu. Uncontrolled NOx data collected during these periods will be used to adjust the SNCR system as necessary.}*

    c. *Opacity*: During startup and shutdown, the stack opacity shall not exceed 20% opacity based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity. This alternate opacity standard does not impose a separate annual testing requirement.

CO and NOx CEMS data excluded due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring shall be summarized and reported in the "Quarterly CO and NOx Emissions Report" required by this permit. *{Permitting Note: Allowances for nitrogen oxides are provided during specific periods in which the control device may not be fully operational because compliance is continuously demonstrated by CEMS data. Similarly, an alternate standard is identified for opacity during startup and shutdown because compliance is readily observable. As sulfur dioxide emissions are a function of the fuel sulfur, it is not expected that startups or shutdowns would cause excess emissions of this pollutant. It is possible that emissions of particulate matter and volatile organic compounds could exceed the permit standards in terms of "lb/MMBtu" during startups and* *shutdowns. However, the Department has good reason to believe that the mass emission rates of these pollutants (lb/hour) will not exceed the specified standards due to reduced loads and fuel firing rates. In any case, the specified test methods are generally applicable only during steady-state operation. Therefore, no alternate emissions standards are specified and compliance shall determined by the test methods and procedures specified in this permit. Compliance with the NESHAP Subpart DDDDD provisions for CO emissions shall be determined in accordance with the federal regulations. The Department's rules and permits cannot waive or supersede a federal requirement.}*

TESTING REQUIREMENTS

13. Boiler Performance Test: Within 180 days of first fire on bagasse, the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted when firing only bagasse and shall be at least three hours long. The boiler steam conditions and production rate shall be monitored and recorded during the test. The bagasse fuel firing rate (tons per hour) shall be calculated and recorded based on the steam parameters. A sample of the as-fired bagasse shall be analyzed for the heating value (Btu/lb) and moisture content (%). The actual heat input rate (MMBtu/hour) shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency of 62%. Results of the test shall be submitted to the Department within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. [Rule 62-4.070(3), F.A.C.]

14. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, Boiler 8 shall be tested to demonstrate initial compliance with the emission standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. The tests shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after the initial startup. Subsequent compliance stack tests for ammonia slip, PM, SO_2, VOC, and opacity shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate when firing only bagasse or bagasse with wood chips. CO CEMS data shall be reported for each run of the required tests for NOx and VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for NOx emissions may be used to demonstrate compliance with the initial stack test standards for this pollutant. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment.

    Permit No. PSD-FL-333C modified the maximum heat input and steaming rates for Boiler 8. Pursuant to Rule 62-297.310(2), F.A.C., operation of Boiler 8 is limited to 110% of the latest test rate until a new test is conducted within 90% to 100% of the revised maximum 24-hour heat input rate that demonstrates compliance with the emissions standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

    {Permitting Note: All initial tests must be conducted at permitted capacity, which is defined as 90% to 100% of the maximum 24-hour heat input rate; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.} [Rules 62-212.400 (PSD) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

15. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
CTM-027	Measurement of Ammonia Slip *{Note: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}*

EPA Method	Description of Method and Comments
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NOx Emissions (Instrumental)
9	Visual Determination of the Opacity
10	Measurement of Carbon Monoxide Emissions (Instrumental) *{Note: The CO test method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NOx, PM, and SO_2 Emission Rates
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

MONITORING REQUIREMENTS

16. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (° F), steam pressure (psig), and steam production rate (lb/hour). Records shall be maintained on site and made available upon request. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

17. Fuel Monitoring: The permittee shall monitor each fuel in accordance with the following provisions. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

    a. *Distillate Oil*: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain an oil flow meter with integrator. At the end of each day that oil is fired, the oil flow meter integrator shall be read and recorded in a written (or electronic) log. Initial compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority. During each federal fiscal year (October 1st to September 30th), the permittee shall take a sample from the storage tank and analyze for the fuel sulfur content. Sampling for the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90 (or more recent versions when available). For each delivery of distillate oil, the permittee shall maintain a permanent record of each certified fuel sulfur analysis provided by the fuel vendor. Records shall specify the date of delivery, the gallons delivered, the fuel sulfur content and test method.

    b. *Bagasse/Wood Chips*: Representative samples of bagasse and wood chips (if stored on site) shall be taken each calendar quarter and analyzed for the following: heating value (Btu/lb, as fired and dry); moisture content (percent by weight); sulfur content (percent by weight, dry); and ash content (percent by weight, dry). Records of the results of these tests shall be maintained on site and made available upon request.

18. CEMS: The permittee shall install, calibrate, operate and maintain continuous emission monitoring systems (CEMS) to measure and record concentrations of CO, NOx, and O_2 in the exhaust of Boiler 8 in a manner sufficient to demonstrate continuous compliance with the CEMS standards specified in this permit. The permittee shall notify the Compliance Authority within one working day of discovering emissions in excess of a CEMS standard subject to the specified averaging period. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial stack tests.

   a. *CO Monitors.* The CO monitor shall be installed, operated and maintained in accordance with the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.

   b. *NOx Monitors.* The NOx monitor shall be installed to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have a maximum span value of 250 ppmvd.

   c. *Diluent Monitors.* An oxygen monitor shall be installed at each CO and NOx monitor location to correct measured CO and NOx emissions to the required oxygen concentrations. The O_2 monitor shall meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

   d. *1-Hour Averages (NOx).* 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of "lb/MMBtu".

   e. *NESHAP Averaging (CO).* CO emissions shall be monitored and recorded pursuant to the applicable requirements in Subpart DDDDD of 40 CFR 63.

   f. *30-Day Averages (NOx).* The 30-day rolling average shall be determined by averaging all 1-hour averages for 30 successive boiler operating days. A boiler operating day begins and ends at midnight of each day and includes any day that fuel is combusted. Final results shall be recorded in terms of "lb/MMBtu".

   g. *Annual Averages (CO).* For each day (midnight to midnight), the CEMS shall record the total CO mass emissions rate (pounds per day). The 12-month rolling total shall be determined by summing the daily CO mass emission rates (pounds per day) for the 12-month period. The result shall be reported in terms of "tons per consecutive 12 months".

   h. *Data Exclusion.* Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 12 in this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

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

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; NESHAP Subpart DDDDD]

19. Alternate Opacity Monitoring Plan: Based on written approval from EPA Region 4, the permittee shall employ the following alternate sampling procedures in lieu of the requirement to install and operate a COMS. The procedures apply to the firing of distillate oil.

 a. A certified EPA Method 9 observer shall perform a twelve-minute opacity test once per daylight shift during the period that the highest distillate oil firing rate occurs.

 b. A certified EPA Method 9 observer shall perform a twelve-minute opacity test when the boiler achieves the normal operational load after a cold boiler startup with distillate oil.

 c. Required observations shall be made in accordance with the provisions of EPA Method 9.

 d. The observer shall maintain a log, which includes all of the information required by EPA Method 9 for each set of observations and the distillate oil firing rate (gph) during the observations.

 e. Within 30 days after each calendar quarter, the permittee shall submit a copy of the observation log to the Compliance Authority for each observation performed during the quarter. The information shall also include a summary of the fuel usage and fuel analysis to verify that Boiler 8 has not exceeded the 10% annual capacity factor limit.

 f. The permittee shall follow the boiler manufacturer's maintenance schedule and procedures to assure that serviceable components are well maintained.

 g. If Boiler 8 exceeds the annual capacity factor limit of 10% for the combustion of distillate oil or is unable to regularly comply with the applicable opacity standard in §60.43b(f) when firing distillate oil, the permittee shall install and operate a COMS in accordance with the provisions of NSPS Subparts A and Db to demonstrate compliance with the opacity standards of the permit.

{Permitting Note: In a letter dated September 22, 2003, EPA Region 4 approved the above Alternate Opacity Monitoring Plan.} [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

20. ESP Monitoring Plan: To ensure proper functioning and effective performance of the electrostatic precipitator (ESP), the permittee shall submit a final ESP Monitoring Plan in accordance with the following requirements.

 a. *Testing Program*: Within 90 days of the initial compliance stack tests, the permittee shall complete a testing program designed to establish the minimum total secondary power input to the ESP that indicates effective performance.

 b. *Monitoring Provisions*: As part of the application for a Title V air operation permit, the permittee shall submit a final ESP Monitoring Plan that includes the following:

1) Based on the testing program, the plan shall specify the minimum total ESP secondary power input requirement (kW, 3-hour block average) that indicates effective performance.
2) The plan shall identify procedures to continuously monitor the ESP secondary voltage and secondary current, which will be used to calculate and record the total ESP secondary power input.
3) Continuous measurements shall be averaged into 15-minute blocks, which in turn will be averaged into 1-hour and 3-hour block averages beginning at the top of each hour, excluding monitoring malfunctions, associated repairs, and required QA/QC activities.
4) Excursions below the minimum level specified require investigation and corrective action.
5) The proposed plan shall incorporate appropriate QA/QC requirements to ensure valid data.

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

21. Urea Injection: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea injection rate for the SNCR system. The permittee shall document the general range of urea flow rates required to meet the NOx standard over the range of load conditions by comparing NOx emissions with urea flow rates. During NOx monitor downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

22. Cyclones: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain the following equipment: flow meter to monitor the water flow rate (gph) for each wet cyclone and a manometer (or equivalent) to monitor the pressure drop (inches of water) across each cyclone. At least once each 8-hour work shift, the flow rate and pressure drop shall be observed and recorded in a written log. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

RECORDS AND REPORTS

23. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (MMBtu/hour), calculated bagasse firing rate (tons/hour), wood chip firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

24. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month of operation: hours of operation, distillate oil consumption, pounds of steam per month, and the updated 12-month rolling totals for each of these operating parameters. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled NOx emissions monitoring and CEMS systems monitor availability for the previous quarter. If CO or NOx CEMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See Appendix G of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

FEDERAL REQUIREMENTS

26. NSPS Subpart Db: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db

in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix D of this permit summarizes these provisions.

27. NESHAP Subpart DDDDD: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63 for "Industrial/Commercial/Institutional Boilers and Process Heaters". Appendix J of this permit summarizes these provisions.

B. Biomass Handling System (EU-027)

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

ID	Emission Unit Description
027	Biomass Handling System

EQUIPMENT

1. Modification of Existing System: The permittee is authorized to modify the existing biomass handling system to accommodate the additional biomass required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed biomass to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the biomass throughput of the handling system. Biomass means bagasse and/or wood chips. [Design; Rule 62-212.400 (PSD), F.A.C.]

2. Equipment: To minimize fugitive particulate matter, biomass conveyors shall be covered and new landing zones shall be installed on conveyor transfer points. The existing dust collectors for the biomass handling system will be removed. The conveyor system will now be completely covered or enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. The bagacillo cyclone separates particles from the gas stream, which are used as part of the cake material on the vacuum filters. The bagacillo system is an existing, unregulated emissions unit.

   [Design; Application No. 0510003-037-AC]

Contents

Appendix A. Citation Formats
Appendix B. General Conditions
Appendix C. Common Requirements
Appendix D. NSPS Provisions
Appendix E. Summary of Final BACT Determinations
Appendix F. Good Combustion and Operating Practices
Appendix G. Quarterly CO and NOx Emissions Report
Appendix H. Shakedown Period
Appendix I. Incidental Amounts of On-Specification Used Oil with Bagasse and or Wood Chips
Appendix J. NESHAP Provisions

Citation Formats

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7 or §60.7]

Means: Title 40, Part 60, Section 7

General Conditions

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

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

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

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

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Unless otherwise specified by permit, the following conditions apply to all emissions units and activities at this facility.

Definitions

1. Excess Emissions: Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot-blowing, load changing or malfunction. [Rule 62-210.200(106), F.A.C.]

2. Shutdown: The cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

3. Startup: The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(246), F.A.C.]

4. Malfunction: Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

Emissions and Controls

5. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

7. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

8. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

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

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

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

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

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

14. <u>Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input</u>: *{Permitting Note: Rule 62-296.405(2), F.A.C. specifies that that new units are subject to the applicable standards in NSPS Subparts D or Da for opacity, particulate matter, sulfur dioxide, and nitrogen oxides. However, NSPS Subpart D is not applicable because the project is also subject to the more recent NSPS Subpart Db, which states that such units are not also subject to NSPS Subpart D. See §60.40b(j) in Appendix D. NSPS Subpart Da is not applicable to this project because the boiler is not an electric utility steam generating unit.}*

15. <u>Carbonaceous Fuel Burning Equipment</u>: Rule 62-296.410(2)(b), F.A.C. establishes the following standards for new emissions units with burners of a capacity equal to or greater than 30 MMBtu per hour total heat input.

    a. *Visible Emissions*: 30 percent opacity except that 40 percent opacity is permissible for not more than two minutes in any one hour.

    b. *Particulate Matter*: 0.2 pounds per MMBtu of heat input of carbonaceous fuel plus 0.1 pounds per million Btu heat input of fossil fuel.

{Permitting Note: The BACT standards specified in the permit are much more stringent than the standards specified in Rules 62-296.405(2) and 62-296.410(2)(b), F.A.C.}

TESTING REQUIREMENTS

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

17. <u>Operating Rate During Testing</u>: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

18. <u>Calculation of Emission Rate</u>: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. <u>Test Procedures</u>: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

20. 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.]

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

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

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

24. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

    1. The type, location, and designation of the emissions unit tested.
    2. The facility at which the emissions unit is located.
    3. The owner or operator of the emissions unit.
    4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
    5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
    6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
    7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
    8. The date, starting time and duration of each sampling run.
    9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
    10. The number of points sampled and configuration and location of the sampling plane.
    11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
    12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

25. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. Information recorded and stored as an electronic file shall be made available within at least three days of a request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
26. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370, F.A.C.]

NSPS Provisions

The following emissions unit is subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60 and adopted by reference in Rule 62-204.800(8), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 60, Subpart A - NSPS General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units

Boiler 8 shall comply with the applicable requirements of Subpart Db in 40 CFR 60, which are adopted by reference in Rule 62-204.800(8), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and related requirements are shown in italics immediately following the pertinent section. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.}

§60.40b Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu/hour.

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(g) In delegating implementation and enforcement authority to a State under Section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State: (1) §60.44b(f); (2) §60.44b(g); and (3) §60.49b(a)(4).

{Permitting Note: NSPS Subpart Db applies because the maximum heat input from oil firing is 562 MMBtu per hour.}

§60.41b Definitions

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydro-desulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference - see §60.17).

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, re-circulated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

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

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 0.5 lb/million BTU heat input.

§60.42b Standard for Sulfur Dioxide

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil (0.5% sulfur by weight). The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emission standard for the boiler flue gas or a percent reduction requirement because the permit restricts distillate oil to no more than 0.05% sulfur by weight. The permit includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.43b Standard for Particulate Matter

(b) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 0.10 lb/million Btu heat input. *{Not applicable; see "Permitting Note" at end of section.}*

(c) On and after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

  (1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

  (2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, 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.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

{Permitting Note: NSPS Subpart Db does not impose a particulate matter emission standard for the boiler flue gas for oil firing because no equipment will be necessary to reduce SO_2 emissions. The permit limits stack opacity to this level or less.}

<u>§60.44b Standard for Nitrogen Oxides</u>

(a) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, 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 coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

(1) Natural gas and distillate oil:

(i) Low heat release rate: 0.10 lb/million BTU of heat input (expressed as NO_2)

{Not applicable; see "Permitting Note" at end of section.}

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixture of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction. *{Not applicable; see "Permitting Note" at end of section.}*

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis. *{Not applicable; see "Permitting Note" at end of section.}*

{Permitting Note: Boiler 8 is a low heat release rate boiler (20,497 Btu/ft^3 on bagasse and 11,184 Btu/ft^3 on distillate oil) and will fire distillate oil during startup or as a supplemental fuel. As described in paragraph (c) above, NSPS Subpart Db does not impose a NOx standard for the boiler flue gas when firing a combination of bagasse and distillate oil because the permit limits distillate oil firing to an annual capacity factor of no more than 10%.}

<u>§60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide</u>

(j) The owner or operator of an affected facility that combusts very low sulfur oil ($\leq$ 0.5% sulfur by weight) is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emissions limit for the boiler flue gas because the boiler will combust only distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(a) The particulate matter emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under §60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under Sec. 60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(d) To determine compliance with the particulate matter and emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8 using the following procedures and reference methods:

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160° C (320° F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets

(iii) Method 5B is to be used only after wet FGD systems.</SUP>

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160° C (320° F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Method 9 is used for determining the opacity of stack emissions.

{Permitting Note: NSPS Subpart Db imposes only a particulate matter and opacity standard because the boiler is restricted to an annual capacity factor of no more than 10% for firing oil. The permit requires testing in accordance with EPA Method 9.}

§60.47b Emission Monitoring for Sulfur Dioxide

(f) The owner or operator of an affected facility that combusts very low sulfur oil (≤ 0.5% sulfur by weight) is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides

(a) The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. *{Permitting Note: In lieu of the continuous opacity monitoring*

requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil.}

§60.49b Reporting and Recordkeeping Requirements

(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) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i), and

(3) 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 sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §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 using the applicable performance specifications in Appendix B. *{Not applicable; see "Permitting Note" at end of section.}*

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

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

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

{Permitting Note: In lieu of the continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur. The permit also restricts the firing of distillate oil to an annual capacity factor of no more than 10%.}

Project Description

U.S. Sugar Corporation proposes to install a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is 633,000 pounds per hour based on a maximum 1-hour heat input rate of 1185 MMBtu per hour. The maximum continuous steam production is 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour averages). Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used fire the primary fuel of bagasse (and wood chips as an alternate or supplemental fuel). Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. The project will also modify the existing bagasse handling system to accommodate the additional bagasse required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed bagasse to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the bagasse throughput of the bagasse handling system.

Air Pollution Control Equipment

Boiler 8: Particulate matter will be controlled by cyclone collectors followed by an electrostatic precipitator (ESP) with approximately a 99% reduction. Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system (~ 50% reduction). Other NOx reduction techniques include low NOx burners for distillate oil, overfire air, and low nitrogen fuels. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide.

Biomass Handling System: To minimize fugitive particulate matter from the biomass handling system, biomass conveyors will be enclosed and new landing zones will be installed on the conveyor transfer points. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. A cyclone separates the particles from the gas stream, which are used as part of the cake material on the vacuum filters.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Pollutant	Standards - Stack Test [a]	Standards – CEMS [b]
EU-027: Biomass Handling System		
PM	Reasonable precautions shall be taken to prevent fugitive dust including confinement and enclosure.	
EU-028: Boiler 8		
CO [d]	Good Combustion Practices	1285 tons per consecutive 12 month rolling total (Avoids PSD Review)
NOx	0.14 lb/MMBtu {Initial demonstration standard; subsequent compliance based on CEMS.}	0.14 lb/MMBtu, 30-day rolling average
PM	0.025 lb/MMBtu [e]	Not Applicable
SO_2 (Surrogate for SAM)	0.06 lb/MMBtu	Not Applicable
	Fuel Specification: Distillate oil shall be new No. 2 oil containing no more than 0.05% sulfur by weight.	
VOC	0.05 lb/MMBtu	Not Applicable
Opacity [c]	During normal operation, stack opacity shall not exceed 20% based on a 6-minute block average. During startup or shutdown, stack opacity shall not exceed 20% based on a 6-minute block average except for one 6-minute block per hour that shall not exceed 27%.	

a. These standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The permit also establishes maximum hourly mass emission rates based on operation at permitted capacity. Compliance with the standards based on stack tests shall be determined by the following EPA stack test methods: NOx (EPA Method 7E); PM (EPA Method 5); SO_2 (EPA Method 6C); VOC (EPA Methods 18 and 25A, as propane); and opacity (EPA Method 9). Compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

b. These standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels and under all load conditions. Compliance with the CO and NOx CEMS-based standards shall be demonstrated by data collected from the required continuous emissions monitoring systems (CEMS) required for these pollutants. The permit allows specific NOx CEMS data to be excluded from the compliance determination (30-day rolling average) when the SNCR system is not functioning due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring. The CO monitor shall meet the applicable requirements in Subpart DDDDD of 40 CFR 63. The NOx monitor shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. An oxygen monitor shall be installed and meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60 to correct the CO and NOx emission rates.

c. NSPS Subpart Db requires a Continuous Opacity Monitoring System (COMS) for new industrial boilers firing "coal, oil, wood or mixtures of these fuels", which applies at all times except startup, shutdown, or malfunction. Therefore, the COMS is required by NSPS Subpart Db when Boiler 8 fires distillate oil alone or in combination with bagasse and/or wood chips. In lieu of the COMS requirements for Boiler 8, EPA Region 4 approved (September 22, 2003) an alternate sampling procedure that includes additional EPA Method 9 observations when firing distillate oil. In addition, the draft permit requires monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP.

d. Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The permit requires the permanent shutdown of Boiler 3 prior to the commercial operation of new Boiler 8.

e. The original PSD permit considered the proposed particulate matter standard for new, large solid fuel fired boilers specified in NESHAP Subpart DDDDD (0.026 lb/MMBtu). The final version of this regulation revised the particulate matter standard to 0.025 lb/MMBtu. For simplicity and clarity, the applicant specifically requested that the BACT standard be reduced to be equivalent to the NESHAP standard. Permit No. PSD-FL-333B revised the standard accordingly.

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original project as well as subsequent revisions.

Good Combustion and Operating Practices

The determination of Best Available Control Technology (BACT) for emissions of carbon monoxide and volatile organic compounds (VOC) from Boiler 8 relied on an efficient boiler design and good combustion and operating practices. To the extent practicable, the permittee shall employ the following procedures to minimize emissions and promote good combustion and pollution control.

Startup and Shutdown

1. Training: All operators and supervisors shall be properly trained to operate and maintain Boiler 8 as well as the pollution control and monitoring equipment in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions during startups, shutdowns, and malfunctions.
2. Boiler Startup: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately 6 to 7 hours to reach the desired superheater steam temperature of 650° F. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. Then, bagasse (and/or wood chips) will be fed until a fire is established across the entire grate. The full steaming rate can be reached about 1 to 3 after first feeding bagasse (and/or wood chips). A boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired.
3. PM Controls: The wet cyclone collectors will be activated before firing any fuel. Prior to activation, the ESP will be purged with ambient air for about 30 to 60 minutes. Distillate oil may be fired during startup prior to energizing the electrostatic precipitator (ESP). The ESP will be on line and functioning properly before any bagasse and/or wood chips are fired. The ESP will remain on line until the bagasse feed has stopped and combustion on the grate is substantially complete.
4. NOx Controls: When the SNCR manufacturer's minimum operating temperature requirement is met, the SNCR system will be activated for NOx control. For a cold startup, this temperature is generally reached within 4 - 5 hours of initial distillate oil firing. During normal operation, the SCNR control system will automatically adjust the urea injection rate and zones to meet the specified NOx standard based on the current urea injection rate, boiler load, furnace temperature, and NOx emissions. During shutdown, the SNCR system shall remain operational until the operating temperature drops below the minimum requirement.
5. Good Combustion Practices: To the extent practicable, the permittee shall maintain the following flue gas levels as indicators of good combustion:
   a. *Oxygen*: The permittee shall install, maintain, and operate a flue gas oxygen monitor on Boiler 8. When firing bagasse during normal operation, the flue gas oxygen content is expected to range from 3% and 4%. High fuel moisture, high ash content, and low load conditions may result in higher flue gas oxygen contents (5% - 6%). When firing only distillate oil, the flue gas exhaust oxygen content is expected to range from 8% and 9% due to tramp air required for cooling of the stoker, pneumatic distributors, and overfire air nozzles. Operators shall ensure that the flue gas oxygen content is sufficient for good combustion.
   b. *Carbon Monoxide (CO)*: Carbon monoxide is an indicator of incomplete fuel combustion. In addition to insufficient oxygen, high fuel moisture, high ash content and low load conditions may result in elevated levels of carbon monoxide. When firing bagasse and/or wood chips during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen. The operator shall use the measured CO emissions at the stack as an indicator of the combustion efficiency and adjust boiler operating conditions as necessary. *{Permitting Note: The stack exhaust is expected to be 1% - 2% (oxygen content) higher than the boiler exhaust due to infiltration from the entire system.}*

   When firing bagasse and/or wood chips, many factors may affect efficient combustion. The above levels represent adherence to good combustion practices under normal operating conditions. Operation outside these levels is not a violation in and of itself. Repeated operation beyond these levels without taking corrective actions to regain good combustion could be considered "circumvention" in accordance with Rule 62-210.650, F.A.C.
6. Boiler Shutdown: To initiate shutdown, the bagasse and/or wood chips fuel feed is terminated. The SNCR systems shall remain functional until operating conditions fall outside of the manufacturer's recommendations. The cyclone collectors and ESP shall continue to operate until solid fuel combustion on the fuel grate is substantially complete.

Quarterly CO and NOx Emissions Report

Current Title V Permit No. ______________________

Facility Name	**ARMS ID No.**	**ARMS EU ID No.**
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	0510003	028

Emissions Unit Description

Boiler 8 is a spreader stoker boiler with maximum continuous steam rate of 500,000 lb/hour. Control equipment includes:
- CO/VOC – Efficient combustion design and good operating practices
- NOx – Low NOx oil burners and selective non-catalytic reduction (SNCR) system
- PM/PM10 – Wet cyclone collectors and electrostatic precipitators

Primary Fuel	**Auxiliary Fuels**
Bagasse – Fibrous plant material remaining after sugarcane is milled	Distillate oil (≤ 0.05% sulfur by weight) Wood chips: alternate or supplemental fuel

Year	**Calendar Quarter of Operation Covered** ***(Check one.)***	**Unit Operation in Calendar Quarter**
	___ 1 ___ 2 ___ 3 ___ 4	_________ hours

Continuous Emissions Monitoring System (CEMS) Information

Pollutant Monitored: _____ CO _____ NOx Manufacturer: ______________________

Date of last certification or audit: ______________ Model No. ______________________

Emission Data Summary

1. Standard: ______________________
2. Hours of excess emissions in reporting period due to:
   a. Startup/shutdown .... ______
   b. Control equipment problems .... ______
   c. Process problems .... ______
   d. Other known causes .... ______
   e. Unknown causes .... ______
2. Total hours of excess emissions .... ______
3. (Total hours of excess emissions) / (Total hours of source operating time) x (100%) .... ______

Note: Report "excess emissions" for any emission averages that are in excess of a permitted emissions standard and averaging period.

CEMS Performance Summary

1. Hours of CEMS downtime in reporting period due to:
   a. Monitor equipment malfunctions .... ______
   b. Non-monitor equipment malfunctions .... ______
   c. Quality assurance calibration .... ______
   d. Other known causes .... ______
   e. Unknown causes .... ______
2. Total hours of CEMS downtime .... ______
3. (Total hours of CEMS downtime) / (Total hours of source operating time) x (100%) .... ______

If monitor availability is not at least 95%, provide a report identifying the problems and a plan of corrective actions that will be taken to achieve 95% availability

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startups: _____ c. Malfunctions: _____ e. Total _____
   b. Shutdowns: _____ d. Uncontrolled NOx Monitoring: _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to the CEMS, process equipment, or control equipment during last quarter.

Emission Rates

On a separate page, report the actual emissions for: each rolling 12-month total (tons) of CO emissions for each month in the quarter, and each 30-day rolling NOx average (ppmvd @ 7% oxygen) for each compliance period in the quarter.

Certification

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

Print Name / Title	**Signature / Date**

Shakedown Period

Boiler 8 will be a new type of spreader-stoker specifically designed for the efficient combustion of bagasse and/or wood chips as an alternate or supplemental fuel. Bagasse is the fibrous byproduct remaining from sugarcane after the milling process. The sugarcane milling season runs from October through April. The proposed startup date for the new boiler is January of 2005, which is approximately halfway through the sugarcane milling season. It is expected that a short, initial shakedown period will be necessary for the boiler prior to shakedown of the SNCR system. Although the facility also includes a refinery that operates during the milling off-season, Boiler 8 is not expected to operate much during the off season unless refinery steam demands are high enough to take advantage of large steam production rate from this unit. For these reasons, the Department authorizes the following shakedown period in accordance with the specific conditions, which are in addition to those specified in Section 3 of the permit.

1. Shakedown: Shakedown is limited to the first 360 calendar days after first fire in the boiler and shall not exceed 180 operational days after first fire in the boiler. An "operational day" is any day that Boiler 8 fires any fuel. During shakedown, Boiler 8 shall not operate more than 60 days during the off-season. For this plant, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. Shakedown is complete once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.
2. SNCR System: During the shakedown period, the permittee is authorized to operate the boiler without the SNCR system for purposes of commissioning the boiler and collecting uncontrolled NOx emissions data, provided:
   a. During the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed a total of 240 hours;
   b. After the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed 2 hours each day; and
   c. Notwithstanding the above periods, the operator shall fully utilize the SNCR system to the extent practicable and according to the manufacturer's recommended procedures.
3. CO and NOx CEMS: The CO and NOx CEMS shall be installed and certified within the first 45 operational days of shakedown. CEMS data collected on the first full day following completion of the shakedown period shall be used to begin demonstrating compliance with the CEMS-based emissions standards of the permit.
4. Initial Stack Tests: All initial stack tests required by this permit shall be conducted during the defined shakedown period, but no later than 60 days after achieving the maximum production rate, which is defined as a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average. The permittee shall provide written notification to the Permitting and Compliance Authorities within 10 days of achieving this maximum production rate.

{Permitting Note: After demonstrating compliance and commencing commercial operation, the conditions of Appendix H will become obsolete and need not be included in the Title V air operation permit. The above requirements do not supersede any federal requirements regarding shakedowns for purposes of complying with NSPS or NESHAP regulations. Boiler 8 has a maximum heat input rate greater than 100 MMBtu/hour and is permitted to fire bagasse as the primary fuel, wood chips as an alternate or supplemental fuel, and distillate oil as a startup and supplemental fuel. As such, it is an "affected facility" as defined in NSPS Subpart Db of 40 CFR 60. This NSPS regulates emissions of sulfur dioxide, particulate matter, opacity, and nitrogen oxides for the firing of coal, oil, or natural gas (or mixtures of these fuels with other fuels). However, the NSPS standards for particulate matter and sulfur dioxide are not applicable because the new boiler does not employ add-on controls to reduce sulfur dioxide emissions. Instead, sulfur dioxide emissions are limited by the firing of very low sulfur distillate oil and bagasse and/or wood chips. In turn, the nitrogen oxide emission standard does not apply because the annual capacity factor for the very low sulfur distillate oil is less than 10% as conditioned by the permit. Only opacity is regulated by NSPS Subpart Db for this new boiler when firing distillate oil. Boiler 8 is also subject to the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.}

Incidental Amounts of On-Specification Used Oil with Bagasse and/or Wood Chips

Description

The facility generates small amounts of on-specification used oil consisting mostly of hydraulic fluids and lubrication oils (<< than 10,000 gallons per year). Leaks or spills of these fluids are removed from the work areas by absorbing with bagasse and/or wood chips and then adding to the common biomass conveyor for firing in any of the boilers. The amount of oil is incidental and would not affect emissions.

Requirements

1. Firing: The permittee may fire incidental amounts of bagasse/on-specification oil with other authorized fuels in any of the mill boilers. To the extent practicable, the bagasse/on-specification oil shall be commingled with bagasse and/or wood chips in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C.]
2. Used Oil Specifications: Incidental amounts of used oil to be fired in the boilers shall be on-specification used oil generated on site at this facility. The permittee shall maintain records sufficient to document that the used oil meets the following requirements:
   a. The used oil shall not contain PCBs.
   b. The used oil shall meet the following EPA specifications for "on-specification used oil" in Subpart B of 40 CFR 279:

      Arsenic shall not exceed 5.0 ppm;
      Cadmium shall not exceed 2.0 ppm;
      Chromium shall not exceed 10.0 ppm;
      Lead shall not exceed 100.0 ppm;
      Total halogens shall not exceed 1000.0 ppm; and
      The flash point shall not be less than 100 degrees F.

   Used oil that does not meet the above requirements shall not be burned at this facility. [Rule 62-4.070, F.A.C.; Subpart B, 40 CFR 279]
3. Records: The permittee shall keep records sufficient to document compliance with the above requirements. The records shall be made available when requested by the Compliance Authority. [Rule 62-4.070, F.A.C.]

NESHAP Provisions

The following emissions unit is subject to applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63 and adopted by reference in Rule 62-204.800(11), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 63, Subpart A - NESHAP General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the National Emission Standards for Hazardous Air Pollutants including: §63.1 Applicability; §63.2 Definitions; §63.3 Units and abbreviations; §63.4 Prohibited activities and circumvention; §63.5 Preconstruction review and notification requirements; §63.6 Compliance with standards and maintenance requirements; §63.7 Performance testing requirements; §63.8 Monitoring requirements; §63.9 Notification requirements; §63.10 Recordkeeping and reporting requirements; §63.11 Control device requirements;§63.12 State authority and delegations; §63.13 Addresses of State air pollution control agencies and EPA Regional Offices; §63.14 Incorporations by reference; §63.15 Availability of information and confidentiality; §63.16 Performance Track Provisions. The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters

Boiler 8 shall comply with all applicable requirements of Subpart DDDDD in 40 CFR 63, which are adopted by reference in Rule 62-204.800(11), F.A.C. For purposes of this regulation, Boiler 8 is classified as a new, large (> 100 MMBtu/hour), solid fuel (bagasse) industrial boiler. As such, the unit is subject to the following primary requirements:

Pollutant	Emission Limits	Requirements
Particulate Matter (PM)	0.025 lb/MMBtu of heat input	• Surrogate limit for total selected metals (TSM) • Compliance by EPA Method 5 stack test • Compliance test establishes allowable "operating limits" (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • Continuous compliance by continuous monitoring (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • A COMS is not required due to the wet cyclone scrubber
Hydrogen Chloride (HCl)	0.02 lb/MMBtu of heat input	• Compliance by EPA Method 26 or 26A stack test • Monitoring is same as for particulate matter • Scrubber pH monitoring not required (EPA Region 4 letter dated September 4, 2005)
Mercury (Hg)	0.000003 lb/MMBtu of heat input	• Compliance by fuel sampling and analysis methods
Carbon Monoxide (CO)	400 ppmvd @ 7% oxygen (30-day rolling average)	• Surrogate limit for organic HAPs • Compliance by data collected from CO CEMS • CEMS shall be installed, operated and maintained in accordance with the provisions of §63.7525

The following pages contain a table of contents for NESHAP Subpart DDDDD as well as the summary tables from this Subpart that are applicable to Boiler 8.

What This Subpart Covers

63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards

63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

General Compliance Requirements

63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the HCl and TSM standards?

Testing, Fuel Analyses, and Initial Compliance Requirements

63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

Continuous Compliance Requirements

63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

Notifications, Reports, and Records

63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

Other Requirements and Information

63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63

Table 1. Emission Limits and Work Practice Standards
Table 2. Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits
Table 3. Operating Limits for Boilers and Process Heaters with Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4. Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Emission Limits
Table 5. Performance Testing Requirements
Table 6. Fuel Analysis Requirements
Table 7. Establishing Operating Limits
Table 8. Demonstrating Continuous Compliance
Table 9. Reporting Requirements
Table 10. Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD

Appendix A. Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B. Applicability of General Provisions to Subpart DDDDD

TABLE 1. Emission Limits and Work Practice Standards

As stated in §63.7500, Boiler 8 shall comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
1. New Large Solid Fuel	a. Particulate Matter (for Total Selected Metals)	0.025 lb per MMBtu of heat input
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input
	c. Mercury	0.000003 lb per MMBtu of heat input
	d. Carbon Monoxide	400 ppmvd corrected to 7 percent oxygen (30-day rolling average) based on data collected from a CO CEMS

The following provisions cover periods of startup, shutdown, and malfunction.

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §63.7 and §63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §63.7525(a) and §63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §63.6(e) and §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance

with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

TABLE 2. Operating Limits for Boilers with Particulate Matter Emission Limits

As stated in §63.7500, Boiler 8 shall comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet Scrubber Control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
3. Electrostatic Precipitator Control	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

TABLE 4. Operating Limits for Boilers with Hydrogen Chloride Limits

As stated in §63.7500, Boiler 8 shall comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet Scrubber Control	Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 5. Performance Testing Requirements (Particulate Matter and Hydrogen Chloride)

As stated in §63.7520, Boiler 8 shall comply with the following performance test requirements:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure particulate matter emissions concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen Chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).

To conduct a performance test for the following pollutant	You must	Using
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the HCl concentration.	Method 26 or 26A in appendix A to part 60.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

TABLE 6. Fuel Analysis Requirements (Mercury)

As stated in §63.7521, Boiler 8 shall comply with the following fuel analysis testing requirements:

To conduct a fuel analysis for the following pollutant	You must	Using
1. Mercury	a. Collect fuel samples (The permittee notes that samples will be taken from a moving belt.)	Procedure in §63.7521(c) or ASTM D2234-001 (for coal)(IBR, see §63.14(b)) or ASTM D6323-98 (2003)(for biomass)(IBR, see §63.14(b)) or equivalent
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent
	c. Prepare composite fuel samples	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) (IBR, see §63.14(b)) or ASTM D5198-92 (2003) (for biomass)(IBR, see §63.14(b)) or equivalent
	d. Determine heat content of the fuel type	ASTM D5865-03a (for coal)(IBR, see §63.14(b)) or ASTM E711-87 (1996) (for biomass)(IBR, see §63.14(b)) or equivalent
	e. Determine moisture content of the fuel type	ASTM D3173-02 (IBR, see §63.14(b)) or ASTM E871-82 (1998)(IBR, see §63.14(b)) or equivalent
	f. Measure mercury concentration in fuel sample.	ASTM D3684-01 (for coal)(IBR, see §63.14(b)) or SW-846-7471A (for solid samples) or SW-846-7470A (for liquid samples)
	g. Convert concentrations into units of "lb/MMBtu" of heat content.	

TABLE 7. Establishing Operating Limits

As stated in §63.7520, Boiler 8 shall comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
1. Particulate Matter	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1)Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a)You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests (b)Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control)	i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c)	(1)Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a)You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests (b)Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
				test run

TABLE 8. Demonstrating Continuous Compliance

As stated in §63.7540, Boiler 8 shall show continuous compliance with the emission limitations as follows:

If you must meet the following operating limits or work practice standards	You must demonstrate continuous compliance by
3. Wet Scrubber Pressure Drop and Liquid Flow Rate *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).
6. Precipitator Secondary Current and Voltage or Total Power Input *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §63.7530(c)
7. Fuel Pollutant Content *(For Mercury)*	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to §63.7540(a).

Compliance with the above operating limits and work practice standards demonstrate continuous compliance with the emission limits for PM, HCl, and Hg. A COMS for opacity is not required due to the wet cyclone scrubber. The CO emission limit (400 ppmvd @ 7% oxygen based on a 30-day rolling average) is set as a work practice standard for controlling emissions of organic HAPs. Continuous compliance with the CO limit is demonstrated by data collected with the required CEMS. Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 9. Reporting Requirements

As stated in §63.7550, Boiler 8 shall comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance Report	a. Information required in §63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	Semiannually according to the requirements in §63.7550(b).

You must submit a(n)	The report must contain	You must submit the report
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in §63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:10 PM
To: 'NSMITH@USSUGAR.COM'; 'PBRIGGS@USSUGAR.COM'; 'DGRIFFIN@USSUGAR.COM'
Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT
Attachments: PSD-FL-333C Boiler 8 - Intent - Project #0510003-037-AC-DRAFT.PDF; PSD-FL-333C Boiler 8 - Revised Draft Permit - Project #0510003-037-AC-DRAFT.PDF; PSD-FL-333C Boiler 8 - TEPD - Project #0510003-037-AC-DRAFT.PDF; Signed Documents for Project #0510003-037-AC-DRAFT.pdf

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The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:06 PM
To: 'DBUFF@GOLDER.COM'; Blackburn, Ron; 'WORLEY.GREGG@EPAMAIL.EPA.GOV'; 'Dee_Morse@nps.gov'
Cc: Koerner, Jeff; Adams, Patty
Subject: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT
Attachments: 0510003.037.AC.D_pdf.zip

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DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Wednesday, February 07, 2007 8:34 AM
To: Adams, Patty; Koerner, Jeff
Subject: FW: U.S. Sugar Corporation - Project #051003-037-AC-DRAFT

From: Don Griffin [mailto:dgriffin@ussugar.com]
Sent: Wednesday, February 07, 2007 8:13 AM
To: Harvey, Mary
Subject: Read: U.S. Sugar Corporation - Project #051003-037-AC-DRAFT

Your message

To: dgriffin@ussugar.com
Subject:

was read on 2/7/2007 8:13 AM.

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:41 PM
To: Adams, Patty; Koerner, Jeff
Subject: FW: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Tuesday, February 06, 2007 4:40 PM
To: Harvey, Mary
Subject: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

Return Receipt

Your document:	U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT
was received by:	Dee Morse/DENVER/NPS
at:	02/06/2007 02:40:01 PM

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:41 PM
To: Adams, Patty; Koerner, Jeff
Subject: FW: U.S. Sugar Corporation - Project #051003-037-AC-DRAFT

From: Peter Briggs [mailto:pbriggs@ussugar.com]
Sent: Tuesday, February 06, 2007 4:40 PM
To: Harvey, Mary
Subject: RE: U.S. Sugar Corporation - Project #051003-037-AC-DRAFT

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Tuesday, February 06, 2007 4:29 PM
To: Neil Smith; Peter Briggs; Don Griffin
Cc: Koerner, Jeff; Adams, Patty
Subject: U.S. Sugar Corporation - Project #051003-037-AC-DRAFT

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Thanks,

Mary Harvey

Dear Sir/Madam:

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DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:30 PM
To: Adams, Patty; Koerner, Jeff
Subject: FW: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

From: Lisa Pickron [mailto:lpickron@ussugar.com]
Sent: Tuesday, February 06, 2007 4:26 PM
To: Harvey, Mary
Subject: Read: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

Your message

To: lpickron@ussugar.com
Subject:

was read on 2/6/2007 4:26 PM.

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:30 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

From: Blackburn, Ron
Sent: Tuesday, February 06, 2007 4:10 PM
To: Harvey, Mary
Subject: RE: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

Ron Blackburn

District Air Program Administrator
Department of Environmental Protection
South District Air Resources Management
Ft. Myers, FL. (239) 332-6975

-----Original Message-----
From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:06 PM
To: 'DBUFF@GOLDER.COM'; Blackburn, Ron; 'WORLEY.GREGG@EPAMAIL.EPA.GOV'; 'Dee_Morse@nps.gov'
Cc: Koerner, Jeff; Adams, Patty
Subject: U.S. Sugar Corporation - Project #0510003-037-AC-DRAFT

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, February 06, 2007 4:29 PM
To: 'NSMITH@USSUGAR.COM'; 'PBRIGGS@USSUGAR.COM'; 'DGRIFFIN@USSUGAR.COM'
Cc: Koerner, Jeff; Adams, Patty
Subject: U.S. Sugar Corporation - Project #051003-037-AC-DRAFT
Attachments: PSD-FL-333C Boiler 8 - Intent - Project #0510003-037-AC-DRAFT.PDF; PSD-FL-333C Boiler 8 - Revised Draft Permit - Project #0510003-037-AC-DRAFT.PDF; PSD-FL-333C Boiler 8 - TEPD - Project #0510003-037-AC-DRAFT.PDF; PSD-FL-333C Boiler 8 - TEPD - Project #0510003-037-AC-DRAFT.PDF; Signed Documents for Project #0510003-037-AC-DRAFT.pdf

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Mary Harvey

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Thank you,

DEP, Bureau of Air Regulation

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

FROM: Jeff Koerner, Air Permitting North

DATE: February 2, 2007

SUBJECT: Revised Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
U.S. Sugar Corporation - Clewiston Sugar Mill and Refinery
Boiler 8 Capacity Increase

U.S. Sugar Corporation submitted an application for the existing Clewiston Sugar Mill and Refinery requesting the following for newly constructed Boiler 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. On December 7th, we issued a draft permit package to accommodate these requests. On January 22, 2007, U.S. Sugar provided comments on the draft permit and requested: correction of the flue gas flow rate for Boiler 8 to 395,000 acfm at 5.5% oxygen (270,000 dscfm at 7% oxygen); and removal of the 5% opacity standard for the bagacillo cyclone, which is an existing unregulated emissions unit that remains unaffected by this project. The changes are acceptable. I recommend withdrawal of the original draft permit package and issuance of this revised draft permit package.

TV/jfk

Attachments

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

February 5, 2007

(Sent by Electronic Mail – Return Receipt Requested)

Neil Smith, Vice President and General Manager
Sugar Processing Operations - Clewiston Sugar Mill and Refinery
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Re: Revised Draft Air Construction Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler No. 8 Capacity Increase

Dear Mr. Smith:

U.S. Sugar Corporation submitted an application for the existing Clewiston Sugar Mill and Refinery requesting the following for newly constructed Boiler 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. The Department issued a draft permit package on December 7, 2006. On January 22, 2007, U.S. Sugar provided comments on the draft permit and requested: correction of the flue gas flow rate for Boiler 8 to 395,000 acfm at 5.5% oxygen (270,000 dscfm at 7% oxygen); and removal of the 5% opacity standard for the bagacillo cyclone, which is an existing unregulated emissions unit that remains unaffected by this project. The Department agrees to these changes. In response to these comments, the Department withdraws the original draft permit package and issues this revised draft permit package.

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

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

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Mr. Neil Smith, V.P. and General Manager
Sugar Processing Operations - Clewiston Sugar Mill and Refinery
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler 8 Capacity Increase
Hendry County, Florida

Facility Location: U.S. Sugar Corporation (applicant) operates an existing sugar mill and refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposed the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. Originally, the Department issued a draft permit package on December 17, 2006. On January 22, 2007, U.S. Sugar provided comments on the draft permit and requested: correction of the flue gas flow rate for Boiler 8 to 395,000 acfm at 5.5% oxygen (270,000 dscfm at 7% oxygen); and removal of the 5% opacity standard for the bagacillo cyclone, which is an existing unregulated emissions unit that remains unaffected by this project. The Department agrees to these changes. In response to these comments, the Department withdraws the original draft permit package and issues this revised draft permit package. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

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

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

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

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

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business

(5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by electronic mail (with return receipt requested) before the close of business on 2/6/07 to the persons listed below.

Mr. Neil Smith, U.S. Sugar (nsmith@ussugar.com)
Mr. Peter Briggs, U.S. Sugar (pbriggs@ussugar.com)
Mr. Don Griffin, U.S. Sugar (dgriffin@ussugar.com)
Mr. David Buff, Golder Associates (dbuff@golder.com)
Mr. Ron Blackburn, SD Office (ron.blackburn@dep.state.fl.us)
Mr. Gregg Worley, EPA Region 4 (worley.gregg@epamail.epa.gov)
Mr. Dee Morse (dee_morse@nps.gov)

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.

Mary L Harvey (Clerk) 2/6/07 (Date)

P.E. CERTIFICATION STATEMENT

PERMITTEE

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Boiler 8 Capacity Increase

PROJECT DESCRIPTION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), which is located in Hendry County, Florida. Boiler 8 is newly constructed in accordance with PSD air construction Permit No. PSD-FL-333. U.S. Sugar submitted an application for the following changes: clarification of startup procedures, modifications of the biomass fuel handling system, and 15% increases in the heat input and steaming rates for the boiler as constructed. Boiler 8 had only limited operation in 2005 - 2006 and has not yet established "normal operations" for a 2-year period. As a result, the Department considers the past actual emissions from Boiler 8 to be the permitted potential emissions. Although maximum short-term emissions rates will increase, annual potential emissions remain restricted by the permit limitation on annual steam production. Therefore, the project is not subject to PSD preconstruction review. However, a revised air quality analysis was conducted, which confirmed that the increased short-term emissions rates will not cause adverse ambient impacts.

The Department issued a draft permit package on December 7, 2006. On January 22, 2007, U.S. Sugar provided comments on the draft permit and requested: correction of the flue gas flow rate for Boiler 8 to 395,000 acfm at 5.5% oxygen (270,000 dscfm at 7% oxygen); and removal of the 5% opacity standard for the bagacillo cyclone, which is an existing unregulated emissions unit that remains unaffected by this project. The changes are acceptable. In response to these comments, the original draft permit package should be withdrawn and this revised draft permit package issued.

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

Jeffery F. Koerner   2-5-07

Jeffery F. Koerner, P.E.
Registration Number: 49441

(Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection

Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Hendry County, Florida

Applicant: The applicant for this project is the U.S. Sugar Corporation. The applicant's authorized representative and mailing address is: Mr. Neil Smith, Vice President and General Manager of Sugar Processing Operations, U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, Florida 33440.

Facility Location: U.S. Sugar Corporation operates an existing sugar mill and refinery, which is located in Hendry County at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: Boiler 8 was originally permitted as a major modification in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality. Subsequent projects must be reviewed for PSD applicability. The applicant proposes the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8: clarification of boiler startup procedures; modification of the biomass fuel handling system; and increases in the heat input and steaming rates. As constructed, this newly designed boiler is actually capable of generating 15% more steam when firing approximately 15% more fuel. Although this will result in potential increases in hourly emission rates, annual potential emissions will not increase because there will be no change in the current limitation on the annual steam production. Initial startup of Boiler 8 was March of 2005. This unit has not established normal operations for a two-year period. Pursuant to Rule 62-210.200(11), F.A.C., there will be no increase in annual emissions and the project is not subject to PSD preconstruction review.

Because the project results in increased potential maximum short-term emissions, an air quality impact analysis was conducted for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter less than 10 microns in diameter (PM_{10}), and sulfur dioxide (SO_2). For these pollutants, the initial air dispersion modeling analysis predicted ambient concentrations below the applicable PSD significant impact levels for the closest PSD Class I Area, which is the Everglades National Park. The initial air dispersion modeling analysis also predicted ambient concentrations below the applicable PSD significant impact levels for the PSD Class II Areas in the vicinity of the plant, except for the 24-hour average SO_2 value. Therefore, a refined analysis was conducted for SO_2 emissions. The subsequent modeling results showed all predicted SO_2 emissions impacts well below the applicable state and federal ambient air quality standards. The following table compares the total maximum impacts predicted in the area with the corresponding maximum allowable PSD Class II increments.

Pollutant	Averaging Time	Total Maximum Impacts ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed
SO_2	Annual	0	20	0%
	24-hour	9	91	10%
	3-hour	39	512	8%

As shown by the air quality analyses, emissions from the modified project will not significantly cause or contribute to a violation of any state or federal ambient air quality standards or PSD increments.

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

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

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

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available for this proceeding.

(Public Notice to be Published in the Newspaper)

REVISED DRAFT PERMIT

PERMITTEE:

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440
Authorized Representative:
Mr. William A. Raiola, V.P. of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Facility ID No. 0510003
Permit Expires: {Date}

FACILITY AND LOCATION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery.

STATEMENT OF BASIS

Boiler 8 was recently constructed under Permit No. PSD-FL-333, as modified. This permitting action is a revision of the air construction permit to specifically address the following items for this unit: increases in the heat input and steaming rates; clarification of startup procedures; and modification of the biomass fuel handling system. The revised 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 perform the proposed work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

DRAFT

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

PROJECT DESCRIPTION

Boiler 8 (EU-028) is a new spreader-stoker boiler with a maximum heat input rate of ~~1030~~ 1185 MMBtu per hour. It will fire bagasse as the primary fuel and wood chips as an alternate or supplemental fuel. Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Air pollution control equipment includes a ~~wet~~ cyclone/electrostatic precipitator (ESP) combination to remove particulate matter and a selective non-catalytic reduction system (SNCR) to reduce nitrogen oxides. Good combustion design and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Low sulfur fuels (i.e., bagasse, wood chips, and distillate oil) will be used to minimize potential emissions of sulfuric acid mist and sulfur dioxide. Monitoring equipment will continuously monitor and record emissions of carbon monoxide and nitrogen oxides. To minimize fugitive particulate matter from the biomass handling system (EU-027), biomass conveyors will be enclosed and new landing zones ~~dust collectors~~ installed on conveyor transfer points.

REGULATORY CLASSIFICATION

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

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

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major facility as defined in Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the applicable New Source Performance Standards in Subpart Db of 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for HAP in Subpart DDDDD of 40 CFR 63.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Formats

Appendix B. General Conditions

Appendix C. Common Requirements

Appendix D. NSPS Provisions

Appendix E. Summary of Final BACT Determinations

Appendix F. Good Combustion and Operating Practices

Appendix G. Quarterly CO and NOx Emissions Report

Appendix H. Shakedown Period

Appendix I. **Incidental Amounts of On-Specification Used Oil with Bagasse**

Appendix J. NESHAP Provisions

RELEVANT DOCUMENTS

The applications, correspondence, and permits related to the following projects are considered relevant documents: original Project No. 0510003-021-AC (PSD-FL-333), revised Project No. 0510003-024-AC (PSD-FL-333A), Project No. 0510003-030-AC (PSD-FL-333B), and Project No. 0510003-037-AC (PSD-FL-333C). Relevant documents are not a part of this permit, but include information specifically related to this permitting action and are on file with the Department.

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of each application shall be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.

3. Rule Citations: Appendix A of this permit explains the methods used to cite rules, regulations, and permits.

4. General Conditions: The permittee shall comply with the general conditions specified in Appendix B of this permit. [Rule 62-4.160, F.A.C.]

5. Common Requirements: The permittee shall comply with the common regulatory requirements specified in Appendix C of this permit. [Chapters 62-4, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.]

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

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(12)(a)~~(6)(b)~~, F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]

8. 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.]

~~9. Relaxations of Restrictions on Pollutant Emitting Capacity. If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7,1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]~~

9. Source Obligation: 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. [Rule 62-212.400(12)(b), F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rule 62-4.030 and Chapters 62-210 and 62-212, F.A.C.]

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

A. Boiler 8 (EU-028)

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

ID	Emission Unit Description
028	*Description*: Boiler 8 will be a membrane wall boiler with balanced draft stoker, overfire air, rotating feeders, and pneumatic spreaders. It will be designed to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. *Fuels*: The primary fuel will be bagasse (SCC No. 1-02-011-01). Wood chips will be fired as an alternate or supplemental fuel (SCC No. 1-02-009-02). Distillate oil (SCC No. 1-02-005-01) containing no more than 0.05% sulfur by weight will be fired as a restricted alternate fuel for startup and supplemental uses. *Capacity*: The maximum continuous steam production is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour averages). *Controls*: Particulate matter is controlled by ~~wet~~ cyclone collectors followed by an electrostatic precipitator (ESP). Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used to minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. *Stack Parameters*: The stack will be 13.0 feet in diameter (maximum) and 199 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of ~~330~~ 315° F and a volumetric flow rate of ~~400,000~~ 395,000 acfm at 5.5% oxygen (~~225,000~~ 270,000 dscfm at 7% oxygen). *CEMS*: Emissions of carbon monoxide and nitrogen oxides will be monitored and recorded by continuous emissions monitoring systems (CEMS).

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions of nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC). Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The final BACT determinations are presented in Appendix E of this permit. Boiler 8 is also subject to the following applicable requirements: Rule 62-296.405, F.A.C. (fossil fuel fired steam generators with more than 250 MMBtu per hour of heat input); Rule 62-296.410, F.A.C. (carbonaceous fuel burning equipment); the federal New Source Performance Standards (NSPS) of Subpart Db (industrial boilers) in 40 CFR 60, which is adopted by reference in Rule 62-204.800(8), F.A.C.; and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) of Subpart DDDDD (industrial boilers) in 40 CFR 63, which is adopted by reference in Rule 62-204.800(11), F.A.C.}

EQUIPMENT

1. Shutdown of Boiler 3: No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of first fire in Boiler 8. Shakedown of the boiler is defined in Appendix H of this permit. During the authorized shakedown period:
   a. Boiler 8 may operate with the other existing boilers to ensure proper integration with the sugar mill and refinery. Any fuel oil fired in Boilers 1, 2, and 3 shall contain no more than 1.6% sulfur by weight.
   b. Boilers 3 and 8 may operate concurrently for no more than 90 individual days during which the combined steam production from Boilers 3 and 8 shall not exceed a daily average of 250,000 pounds per hour. After first fire and shakedown of Boiler 8, Boiler 3 shall be permanently shutdown prior to commencement of commercial operation of Boiler 8 or after completion of the crop season, whichever

occurs first. For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September.

No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of the permanent shutdown of Boiler 3 and of beginning commercial operation of Boiler 8. *{Permitting Note: Emissions decreases from the shutdown of Boiler 3 were used in the netting analysis to avoid PSD review of CO emissions for this project. The authorized shakedown period provides a reasonable period to start up the newly designed Boiler 8, test operations, and make necessary adjustments. A limited amount of concurrent operation is allowed because Boiler 8 is replacing Boiler 3 and must be fully tested during the crop season.}* [Design; Rule 62-212.400 (PSD), F.A.C.]

2. Construction of Boiler 8: The permittee is authorized to construct a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at design conditions of 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is ~~550,000~~ 633,000 pounds per hour based on a maximum 1-hour heat input rate of ~~1030~~ 1185 MMBtu per hour. Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse and/or wood chips. Low NOx burners will be used to fire distillate oil as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. Within 90 days of selecting the final design and vendor, the permittee shall submit the final primary design details of the proposed boiler. [Design]

3. Air Pollution Control Equipment: To comply with the standards of this permit, the permittee shall install the following air pollution control equipment.

   a. *~~Wet~~ Cyclone Collectors*: The permittee shall design, install, operate, and maintain a pre-control device prior to the electrostatic precipitator (ESP) to remove entrained sand and large particles in the flue gas. The purpose of the pre-control device is to prevent excessive equipment wear and overloading of the ESP. ~~The preliminary design is to locate t~~Two wet and one dry cyclone collectors are installed in parallel before the induced draft fan. ~~Upon written approval of the Department, equivalent equipment may be installed.~~

   b. *ESP*: The permittee shall design, install, operate, and maintain an electrostatic precipitator (ESP) to remove particulate matter from the flue gas exhaust and achieve the particulate matter standards specified in this permit. The ESP shall include an automated rapping system that can adjust rapping frequency and intensity to prevent re-entrainment of fly ash. The ESP shall be on line and functioning properly whenever bagasse and/or wood chips is fired.

   c. *SNCR*: The permittee shall design, install, operate, and maintain a urea-based selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide emissions in the flue gas exhaust and achieve the nitrogen oxides emissions standards specified in this permit. The system shall include automated control of urea injection for at least three injection zones to respond to varying load and flue gas conditions. Urea injection rates and zones will be determined based on parameters such as the current injection rate, furnace temperature profile, fuels, steam load, oxygen level, carbon monoxide level, and nitrogen oxide emissions.

   Within 90 days of selecting the final equipment designs and vendors, the permittee shall submit the final primary design details for the proposed pollution controls. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary fuel, wood chips as an alternate or supplemental fuel, and distillate oil as a restricted alternate fuel for startup and supplemental uses. Bagasse

is the fibrous material remaining after sugarcane is milled. Only new No. 2 (or superior) distillate oil containing no more than 0.05% sulfur by weight shall be fired. In addition, incidental amounts of on-specification used oil commingled with bagasse may be fired in Boiler 8 in accordance with the requirements in Appendix I of this permit. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

5. Boiler Capacities and Restrictions: The hours of operation are not restricted (8760 hours/year). The maximum continuous steam production capacity (24-hour average) is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour average). The total maximum heat input from the oil burners is 562 MMBtu per hour (4161 gallons/hour). Boiler 8 shall not exceed the following operational levels.
   a. ~~12,000,000~~ 13,800,000 pounds of steam per day (equivalent to ~~500,000~~ 575,000 pounds of steam per hour and ~~936~~ 1077 MMBtu per hour, 24-hour averages);
   b. 3.6135 x 10^{+09} pounds of steam per consecutive 12 months (equivalent to 6,767,100 MMBtu per year);
   c. 99,864 gallons of distillate oil per day (equivalent to 13,488 MMBtu per day); and
   d. 6,073,600 gallons of distillate oil per consecutive 12 months (equivalent to 819,936 MMBtu per year).

   {Permitting Note: The short-term restrictions form the basis of the Air Quality Analysis. The restriction on annual steam production is a surrogate for heat input and allowed the project to avoid PSD applicability for carbon monoxide emissions. The annual oil firing restriction results in an annual capacity factor of 10% or less, which avoids specific requirements in NSPS Subpart Db.} [Design; Rules 62-4.070(3), 62-212.400 (PSD), 62-210.200(PTE), F.A.C.; NSPS Subpart Db]

6. Good Combustion and Operating Practices: The permittee shall follow the good combustion and operating practices identified in Appendix F of this permit. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: See Appendix E of this permit for a summary of the final BACT determinations.}

7. Standards Based on Stack Tests: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The mass emission rates (pounds per hour) are based on the maximum 24-hour heat input rate. Unless otherwise specified, compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.
   a. Ammonia Slip: As determined by EPA Conditional Test Method CTM-027, ammonia slip shall not exceed 20 ppmvd @ 7% oxygen. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]
   b. Carbon Monoxide (CO): To the extent practicable, short term emissions of carbon monoxide shall be controlled by implementing the good combustion and operating practices identified in Appendix F. [Rules 62-4.070(3), F.A.C.]
   c. Nitrogen Oxides (NOx): As determined by EPA Method 7E stack test, NOx emissions shall not exceed 0.14 lb/MMBtu and ~~131.0~~ 150.8 pounds per hour. *{Permitting Note: This standard is an "initial demonstration standard" intended to show the capabilities of the SNCR system as designed. After the initial compliance test, subsequent compliance shall be demonstrated with the long-term CEMS-based standard specified in Condition 8b.}* [Rule 62-212.400 (PSD), F.A.C.]
   d. Opacity: As determined by EPA Method 9 observations or COMS, the stack opacity shall not exceed 20% based on a 6-minute average. [Rule 62-212.400 (PSD), F.A.C.]
   e. Particulate Matter (PM/PM_{10}): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.025 lb/MMBtu and ~~23.4~~ 26.9 pounds per hour. [Rule 62-212.400 (PSD), F.A.C.; 40 CFR

63.7500]

f. Sulfur Dioxide (SO_2): As determined by EPA Method 6C stack test, SO_2 emissions shall not exceed 0.06 lb/MMBtu and ~~56.2~~ 64.6 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400 (PSD), F.A.C.]

g. Volatile Organic Compounds (VOC): As determined by EPA Methods 18 and 25A stack tests, VOC emissions shall not exceed 0.05 lb/MMBtu and ~~46.8~~ 53.9 pounds per hour measured as propane. For this permit, "VOC" emissions shall be defined as the total hydrocarbons (THC) measured by EPA Method 25A less the sum of the methane and ethane emissions as measured by EPA Method 18 on a concurrent sample. Alternatively, the permittee may elect to assume that all THC are regulated VOC emissions. [Rule 62-212.400 (PSD), F.A.C.]

h. Hydrogen Chloride (HCl): As determined by EPA Method 26 or 26A stack test, HCl emissions shall not exceed 0.02 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7500]

i. Mercury (Hg): As determined by the fuel analysis requirements specified in §63.7521 and Table 6 of Subpart DDDDD in 40 CFR 63, mercury emissions shall not exceed 0.000003 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7521]

8. Standards Based on CEMS: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels and under all load conditions.

   a. Carbon Monoxide (CO):

      1) As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 7% oxygen based on a 30-day rolling average. Carbon monoxide emission levels must be maintained below this work practice standard at all times except during periods of startup, shutdown, malfunction, and when the boiler or process heater is operating at less than 50% of rated capacity. For purposes of calculating data averages, data recorded during the following periods must not be used: periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler is operating at less than 50% of its rated capacity. All the data collected during all other periods must be used in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements. [40 CFR 63.7500(1), 63.7525(a)(6), 63.7540(a)(10) and Table 1 of Subpart DDDDD]

      2) As determined by CEMS data, CO emissions shall not exceed 1285 tons during any consecutive 12 months including periods of startup, shutdown, and malfunction. *{Permitting Note: Compliance with the annual mass emission standard ensures that the project is not subject to PSD preconstruction review for CO emissions.}* [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

   b. Nitrogen Oxides (NOx): As determined by CEMS data, NOx emissions shall not exceed 0.14 lb/MMBtu based on a 30-day rolling average. [Rule 62-212.400 (PSD), F.A.C.]

{Permitting Note: Appendix H of this permit specifies additional requirements regarding the initial shakedown period and initial demonstration of compliance for the CEMS-based standards.}

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

9. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with the following. If the permittee is

temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

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

11. <u>Excess Emissions - Allowed</u>: Unless otherwise specified by this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

12. <u>Excess Emissions – CO, NOx, and Opacity Requirements</u>: As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.

    a. *CO Emissions*: All valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements.

    b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, malfunction, and authorized periods of uncontrolled NOx monitoring may be excluded from the determination of compliance with the 30-day rolling emissions standard, provided:

        1) Best operational practices are used to minimize emissions;

        2) For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional;

        3) For malfunctions, excluded data shall not exceed two hours in any 24-hour period (eight 15-minute CEMS blocks or quadrants of an hour). The permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

        4) For two hours each month, the permittee may operate the boiler without the SNCR system in order to collect uncontrolled NOx emissions data with the CEMS. For purposes of collecting uncontrolled NOx emissions data to adjust the SNCR system, excluded data shall not exceed two, 1-hour values during any calendar month. *{Permitting Note: Based on the final design specifications, uncontrolled NOx emissions are expected to be 0.30 lb/MMBtu. Uncontrolled NOx data collected during these periods will be used to adjust the SNCR system as necessary.}*

    c. *Opacity*: During startup and shutdown, the stack opacity shall not exceed 20% opacity based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity. This alternate opacity standard does not impose a separate annual testing requirement.

    CO and NOx CEMS data excluded due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring shall be summarized and reported in the "Quarterly CO and NOx Emissions Report" required by this permit. *{Permitting Note: Allowances for nitrogen oxides are provided during specific* *periods in which the control device may not be fully operational because compliance is continuously demonstrated by CEMS data. Similarly, an alternate standard is identified for opacity during startup and shutdown because compliance is readily observable. As sulfur dioxide emissions are a function of the fuel sulfur, it is not expected that startups or shutdowns would cause excess emissions of this pollutant. It is possible that emissions of particulate matter and volatile organic compounds could exceed the permit standards in terms of "lb/MMBtu" during startups and shutdowns. However, the Department has good reason to believe that the mass emission rates of these pollutants (lb/hour) will not exceed the specified standards due to reduced loads and fuel firing rates. In any case, the specified test methods are generally applicable only during steady-state operation. Therefore, no alternate emissions standards are specified and compliance shall determined by the test methods and procedures specified in this permit. Compliance with the NESHAP Subpart DDDDD provisions for CO emissions shall be determined in accordance with the federal regulations. The Department's rules and permits cannot waive or supersede a federal requirement.}*

TESTING REQUIREMENTS

13. Boiler Performance Test: Within 180 days of first fire on bagasse, the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted when firing only bagasse and shall be at least three hours long. The boiler steam conditions and production rate shall be monitored and recorded during the test. The bagasse fuel firing rate (tons per hour) shall be calculated and recorded based on the steam parameters. A sample of the as-fired bagasse shall be analyzed for the heating value (Btu/lb) and moisture content (%). The actual heat input rate (MMBtu/hour) shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency of 62%. Results of the test shall be submitted to the Department within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. [Rule 62-4.070(3), F.A.C.]

14. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, Boiler 8 shall be tested to demonstrate initial compliance with the emission standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. The tests shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after the initial startup. Subsequent compliance stack tests for ammonia slip, PM, SO_2, VOC, and opacity shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate when firing only bagasse or bagasse with wood chips. CO CEMS data shall be reported for each run of the required tests for NOx and VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for NOx emissions may be used to demonstrate compliance with the initial stack test standards for this pollutant. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment.

    Permit No. PSD-FL-333C modified the maximum heat input and steaming rates for Boiler 8. Pursuant to Rule 62-297.310(2), F.A.C., operation of Boiler 8 is limited to 110% of the latest test rate until a new test is conducted within 90% to 100% of the revised maximum 24-hour heat input rate that demonstrates compliance with the emissions standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

    {Permitting Note: All initial tests must be conducted at permitted capacity, ~~between~~ which is defined as 90% ~~and~~ to 100% of the maximum 24-hour heat input rate ~~permitted capacity~~; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.} [Rules 62-212.400 (PSD) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

15. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
CTM-027	Measurement of Ammonia Slip *{Note: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}*
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NOx Emissions (Instrumental)
9	Visual Determination of the Opacity
10	Measurement of Carbon Monoxide Emissions (Instrumental) *{Note: The CO test method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NOx, PM, and SO_2 Emission Rates
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

MONITORING REQUIREMENTS

16. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (° F), steam pressure (psig), and steam production rate (lb/hour). Records shall be maintained on site and made available upon request. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

17. Fuel Monitoring: The permittee shall monitor each fuel in accordance with the following provisions. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

    a. *Distillate Oil*: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain an oil flow meter with integrator. At the end of each day that oil is fired, the oil flow meter integrator shall be read and recorded in a written (or electronic) log. Initial compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority. During each federal fiscal year (October 1st to September 30th), the permittee shall take a sample from the storage tank and analyze for the fuel sulfur content. Sampling for the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90 (or more recent versions when available). For each delivery of distillate oil, the permittee shall maintain a permanent record of each certified fuel sulfur analysis provided by the fuel vendor. Records shall specify the date of delivery, the gallons delivered, the fuel sulfur content and test method.

    b. *Bagasse/Wood Chips*: Representative samples of bagasse and wood chips (if stored on site) shall be taken each calendar quarter and analyzed for the following: heating value (Btu/lb, as fired and dry); moisture content (percent by weight); sulfur content (percent by weight, dry); and ash content (percent by weight, dry). Records of the results of these tests shall be maintained on site and made available upon request.

18. CEMS: The permittee shall install, calibrate, operate and maintain continuous emission monitoring systems (CEMS) to measure and record concentrations of CO, NOx, and O_2 in the exhaust of Boiler 8 in a manner sufficient to demonstrate continuous compliance with the CEMS standards specified in this permit. The permittee shall notify the Compliance Authority within one working day of discovering emissions in excess of a CEMS standard subject to the specified averaging period. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial stack tests.

   a. *CO Monitors.* The CO monitor shall be installed, operated and maintained in accordance with the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.

   b. *NOx Monitors.* The NOx monitor shall be installed to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have a maximum span value of 250 ppmvd.

   c. *Diluent Monitors.* An oxygen monitor shall be installed at each CO and NOx monitor location to correct measured CO and NOx emissions to the required oxygen concentrations. The O_2 monitor shall meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

   d. *1-Hour Averages (NOx).* 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of "lb/MMBtu".

   e. *NESHAP Averaging (CO).* CO emissions shall be monitored and recorded pursuant to the applicable requirements in Subpart DDDDD of 40 CFR 63.

   f. *30-Day Averages (NOx).* The 30-day rolling average shall be determined by averaging all 1-hour averages for 30 successive boiler operating days. A boiler operating day begins and ends at midnight of each day and includes any day that fuel is combusted. Final results shall be recorded in terms of "lb/MMBtu".

   g. *Annual Averages (CO).* For each day (midnight to midnight), the CEMS shall record the total CO mass emissions rate (pounds per day). The 12-month rolling total shall be determined by summing the daily CO mass emission rates (pounds per day) for the 12-month period. The result shall be reported in terms of "tons per consecutive 12 months".

h. *Data Exclusion.* Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 12 in this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

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

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; NESHAP Subpart DDDDD]

19. Alternate Opacity Monitoring Plan: Based on written approval from EPA Region 4, the permittee shall employ the following alternate sampling procedures in lieu of the requirement to install and operate a COMS. The procedures apply to the firing of distillate oil.

a. A certified EPA Method 9 observer shall perform a twelve-minute opacity test once per daylight shift during the period that the highest distillate oil firing rate occurs.

b. A certified EPA Method 9 observer shall perform a twelve-minute opacity test when the boiler achieves the normal operational load after a cold boiler startup with distillate oil.

c. Required observations shall be made in accordance with the provisions of EPA Method 9.

d. The observer shall maintain a log, which includes all of the information required by EPA Method 9 for each set of observations and the distillate oil firing rate (gph) during the observations.

e. Within 30 days after each calendar quarter, the permittee shall submit a copy of the observation log to the Compliance Authority for each observation performed during the quarter. The information shall also include a summary of the fuel usage and fuel analysis to verify that Boiler 8 has not exceeded the 10% annual capacity factor limit.

f. The permittee shall follow the boiler manufacturer's maintenance schedule and procedures to assure that serviceable components are well maintained.

g. If Boiler 8 exceeds the annual capacity factor limit of 10% for the combustion of distillate oil or is unable to regularly comply with the applicable opacity standard in §60.43b(f) when firing distillate oil, the permittee shall install and operate a COMS in accordance with the provisions of NSPS Subparts A and Db to demonstrate compliance with the opacity standards of the permit.

{Permitting Note: In a letter dated September 22, 2003, EPA Region 4 approved the above Alternate Opacity Monitoring Plan.} [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

20. ESP Monitoring Plan: To ensure proper functioning and effective performance of the electrostatic precipitator (ESP), the permittee shall submit a final ESP Monitoring Plan in accordance with the following requirements.

a. *Testing Program*: Within 90 days of the initial compliance stack tests, the permittee shall complete a testing program designed to establish the minimum total secondary power input to the ESP that indicates effective performance.

b. *Monitoring Provisions*: As part of the application for a Title V air operation permit, the permittee shall submit a final ESP Monitoring Plan that includes the following:

1) Based on the testing program, the plan shall specify the minimum total ESP secondary power input requirement (kW, 3-hour block average) that indicates effective performance.
2) The plan shall identify procedures to continuously monitor the ESP secondary voltage and secondary current, which will be used to calculate and record the total ESP secondary power input.
3) Continuous measurements shall be averaged into 15-minute blocks, which in turn will be averaged into 1-hour and 3-hour block averages beginning at the top of each hour, excluding monitoring malfunctions, associated repairs, and required QA/QC activities.
4) Excursions below the minimum level specified require investigation and corrective action.
5) The proposed plan shall incorporate appropriate QA/QC requirements to ensure valid data.

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

21. SNCR Urea Injection: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea injection rate for the SNCR system. The permittee shall document the general range of urea flow rates required to meet the NOx standard over the range of load conditions by comparing NOx emissions with urea flow rates. During NOx monitor downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

22. ~~Wet~~ Cyclones: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain the following equipment ~~on each wet cyclone~~: flow meter to monitor the water flow rate (gph) for each wet cyclone and a manometer (or equivalent) to monitor the pressure drop (inches of water) across each cyclone. At least once each 8-hour work shift, the flow rate and pressure drop shall be observed and recorded in a written log. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

RECORDS AND REPORTS

23. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (MMBtu/hour), calculated bagasse firing rate (tons/hour), wood chip firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

24. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month of operation: hours of operation, distillate oil consumption, pounds of steam per month, and the updated 12-month rolling totals for each of these operating parameters. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled NOx emissions monitoring and CEMS systems monitor availability for the previous quarter. If CO or NOx CEMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See

Appendix G of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

FEDERAL REQUIREMENTS

26. NSPS Subpart Db: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix D of this permit summarizes these provisions.
27. NESHAP Subpart DDDDD: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63 for "Industrial/Commercial/Institutional Boilers and Process Heaters". Appendix J of this permit summarizes these provisions.

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

ID	Emission Unit Description
027	Biomass Handling System

EQUIPMENT

1. Modification of Existing System: The permittee is authorized to modify the existing biomass handling system to accommodate the additional biomass required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed biomass to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the biomass throughput of the handling system. Biomass means bagasse and/or wood chips. [Design; Rule 62-212.400 (PSD), F.A.C.]

2. ~~Air Pollution Control~~ Equipment: To minimize fugitive particulate matter, biomass conveyors shall be enclosed and ~~. Dust collectors~~ new landing zones shall be installed on conveyor transfer points. The conveyor system will now be completely enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. The bagacillo cyclone separates particles from the gas stream, which are used as part of the cake material on the vacuum filters. The bagacillo system is an existing, unregulated emissions unit. ~~The preliminary design for the biomass conveyor dust collection system is based on the following specifications.~~

~~Dust Collector~~	~~Manufacturer~~	~~Model No.~~	~~Flow Rate (acfm)~~	~~Outlet (grains/afc)~~	~~Approximate Outlet Height (feet)~~
~~1~~	~~Prime Systems~~	~~BV-6X8-120~~	~~3550~~	~~0.02~~	~~57~~
~~2~~	~~Prime Systems~~	~~BV-8X8-120~~	~~3100~~	~~0.02~~	~~62~~
~~3~~	~~Prime Systems~~	~~BV-8X7-120~~	~~4725~~	~~0.02~~	~~61~~
~~4~~	~~Prime Systems~~	~~BV-6X8-120~~	~~3550~~	~~0.02~~	~~57~~
~~5~~	~~Prime Systems~~	~~BV-6X8-120~~	~~3550~~	~~0.02~~	~~57~~

~~*{Permitting Note: This system has previously been permitted and is under construction. The original plan called for the installation of six dust collectors. With the elimination of transfer belt conveyor No. 2, only the five dust collectors described above will be installed.}*~~ [Design; Application No. 0510003-037-AC]

~~**EMISSIONS STANDARDS**~~

~~3. Opacity: As determined by EPA Method 9, there shall be no visible emissions (≤ 5% opacity) from the dust collector outlets. [Rule 62-212.400 (PSD), F.A.C.]~~

~~**TESTING REQUIREMENTS**~~

~~4. Opacity Tests: Within 180 days of completing construction of the biomass handling system and during the sugar mill season, an initial test shall be conducted in accordance with EPA Method 9 to demonstrate compliance with the opacity standard. Tests shall be conducted while the sugar mill and boilers are in normal operation. Each test shall be at least 30 minutes in duration. Subsequent tests shall be repeated for each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the opacity standard. [Rules 62-212.400 (PSD) and 62-297.310(7)(a)4, F.A.C.]~~

~~**REPORTS**~~

~~5. Test Report: Within 45 days of conducting an opacity test, the permittee shall submit a report to the Compliance Authority summarizing the results of the test. [Rule 62-297.310(8), F.A.C.]~~

Contents

Appendix A. Citation Formats
Appendix B. General Conditions
Appendix C. Common Requirements
Appendix D. NSPS Provisions
Appendix E. Summary of Final BACT Determinations
Appendix F. Good Combustion and Operating Practices
Appendix G. Quarterly CO and NOx Emissions Report
Appendix H. Shakedown Period
Appendix I. Incidental Amounts of On-Specification Used Oil with Bagasse and or Wood Chips
Appendix J. NESHAP Provisions

Citation Formats

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7 or §60.7]

Means: Title 40, Part 60, Section 7

General Conditions

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

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Unless otherwise specified by permit, the following conditions apply to all emissions units and activities at this facility.

Definitions

1. Excess Emissions: Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot-blowing, load changing or malfunction. [Rule 62-210.200(106), F.A.C.]
2. Shutdown: The cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]
3. Startup: The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(246), F.A.C.]
4. Malfunction: Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

Emissions and Controls

5. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
7. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
8. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
9. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
10. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
11. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]
12. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as confining, containing, covering, and/or applying water to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input: *{Permitting Note: Rule 62-296.405(2), F.A.C. specifies that that new units are subject to the applicable standards in NSPS Subparts D or Da for opacity, particulate matter, sulfur dioxide, and nitrogen oxides. However, NSPS Subpart D is not applicable because the project is also subject to the more recent NSPS Subpart Db, which states that such units are not also subject to NSPS Subpart D. See §60.40b(j) in Appendix D. NSPS Subpart Da is not applicable to this project because the boiler is not an electric utility steam generating unit.}*

15. Carbonaceous Fuel Burning Equipment: Rule 62-296.410(2)(b), F.A.C. establishes the following standards for new emissions units with burners of a capacity equal to or greater than 30 MMBtu per hour total heat input.

    a. *Visible Emissions*: 30 percent opacity except that 40 percent opacity is permissible for not more than two minutes in any one hour.

    b. *Particulate Matter*: 0.2 pounds per MMBtu of heat input of carbonaceous fuel plus 0.1 pounds per million Btu heat input of fossil fuel.

{Permitting Note: The BACT standards specified in the permit are much more stringent than the standards specified in Rules 62-296.405(2) and 62-296.410(2)(b), F.A.C.}

TESTING REQUIREMENTS

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

17. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

20. 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.]

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

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

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

24. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

Records and Reports

25. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. Information recorded and stored as an electronic file shall be made available within at least three days of a request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
26. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370, F.A.C.]

The following emissions unit is subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60 and adopted by reference in Rule 62-204.800(8), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of ~~500,000~~ 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 60, Subpart A - NSPS General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units

Boiler 8 shall comply with the applicable requirements of Subpart Db in 40 CFR 60, which are adopted by reference in Rule 62-204.800(8), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and related requirements are shown in italics immediately following the pertinent section. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.}

§60.40b Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu/hour.

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(g) In delegating implementation and enforcement authority to a State under Section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State: (1) §60.44b(f); (2) §60.44b(g); and (3) §60.49b(a)(4).

{Permitting Note: NSPS Subpart Db applies because the maximum heat input from oil firing is 562 MMBtu per hour.}

§60.41b Definitions

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydro-desulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference - see §60.17).

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, re-circulated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

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

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 0.5 lb/million BTU heat input.

§60.42b Standard for Sulfur Dioxide

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil (0.5% sulfur by weight). The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emission standard for the boiler flue gas or a percent reduction requirement because the permit restricts distillate oil to no more than 0.05% sulfur by weight. The permit includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.43b Standard for Particulate Matter

(b) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 0.10 lb/million Btu heat input. *{Not applicable; see "Permitting Note" at end of section.}*

(c) On and after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

   (1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

   (2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, 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.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

{Permitting Note: NSPS Subpart Db does not impose a particulate matter emission standard for the boiler flue gas for oil firing because no equipment will be necessary to reduce SO_2 emissions. The permit limits stack opacity to this level or less.}

§60.44b Standard for Nitrogen Oxides

(a) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, 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 coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

(1) Natural gas and distillate oil:

(i) Low heat release rate: 0.10 lb/million BTU of heat input (expressed as NO_2)

{Not applicable; see "Permitting Note" at end of section.}

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixture of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction. *{Not applicable; see "Permitting Note" at end of section.}*

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis. *{Not applicable; see "Permitting Note" at end of section.}*

{Permitting Note: Boiler 8 is a low heat release rate boiler (20,497 Btu/ft^3 on bagasse and 11,184 Btu/ft^3 on distillate oil) and will fire distillate oil during startup or as a supplemental fuel. As described in paragraph (c) above, NSPS Subpart Db does not impose a NOx standard for the boiler flue gas when firing a combination of bagasse and distillate oil because the permit limits distillate oil firing to an annual capacity factor of no more than 10%.}

§60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(j) The owner or operator of an affected facility that combusts very low sulfur oil ($\leq$ 0.5% sulfur by weight) is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emissions limit for the boiler flue gas because the boiler will combust only distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(a) The particulate matter emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under §60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under Sec. 60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(d) To determine compliance with the particulate matter and emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8 using the following procedures and reference methods:

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160° C (320° F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets

(iii) Method 5B is to be used only after wet FGD systems.</SUP>

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160° C (320° F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Method 9 is used for determining the opacity of stack emissions.

{Permitting Note: NSPS Subpart Db imposes only a particulate matter and opacity standard because the boiler is restricted to an annual capacity factor of no more than 10% for firing oil. The permit requires testing in accordance with EPA Method 9.}

§60.47b Emission Monitoring for Sulfur Dioxide

(f) The owner or operator of an affected facility that combusts very low sulfur oil (≤ 0.5% sulfur by weight) is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides

(a) The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. *{Permitting Note: In lieu of the continuous opacity monitoring*

requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil.}

§60.49b Reporting and Recordkeeping Requirements

(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) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i), and

(3) 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 sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §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 using the applicable performance specifications in Appendix B. *{Not applicable; see "Permitting Note" at end of section.}*

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

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

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

{Permitting Note: In lieu of the continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur. The permit also restricts the firing of distillate oil to an annual capacity factor of no more than 10%.}

Summary of Final BACT Determinations

Project Description

U.S. Sugar Corporation proposes to install a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is ~~550,000~~ 633,000 pounds per hour based on a maximum 1-hour heat input rate of ~~1030~~ 1185 MMBtu per hour. The maximum continuous steam production is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour averages). Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used fire the primary fuel of bagasse (and wood chips as an alternate or supplemental fuel). Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. The project will also modify the existing bagasse handling system to accommodate the additional bagasse required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed bagasse to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the bagasse throughput of the bagasse handling system.

Air Pollution Control Equipment

Boiler 8: Particulate matter will be controlled by ~~wet~~ cyclone collectors followed by an electrostatic precipitator (ESP) with approximately a 99% reduction. Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system (~ 50% reduction). Other NOx reduction techniques include low NOx burners for distillate oil, overfire air, and low nitrogen fuels. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide.

Biomass Handling System: To minimize fugitive particulate matter from the biomass handling system, biomass conveyors will be enclosed and ~~dust collectors~~ new landing zones will be installed on the conveyor transfer points. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. A cyclone separates the particles from the gas stream, which are used as part of the cake material on the vacuum filters.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Pollutant	Standards - Stack Test [a]	Standards – CEMS [b]
EU-027: Biomass Handling System		
PM ~~Opacity [c]~~	Reasonable precautions shall be taken to prevent fugitive dust including confinement and enclosure. ~~There shall be no visible emissions (≤ 5% opacity) from the dust collector outlets.~~	
EU-028: Boiler 8		
CO [d]	Good Combustion Practices	1285 tons per consecutive 12 month rolling total (Avoids PSD Review)
NOx	0.14 lb/MMBtu {Initial demonstration standard; subsequent compliance based on CEMS.}	0.14 lb/MMBtu, 30-day rolling average
PM	0.025 lb/MMBtu [e]	Not Applicable
SO_2 (Surrogate for SAM)	0.06 lb/MMBtu	Not Applicable
	Fuel Specification: Distillate oil shall be new No. 2 oil containing no more than 0.05% sulfur by weight.	
VOC	0.05 lb/MMBtu	Not Applicable
Opacity [c]	During normal operation, stack opacity shall not exceed 20% based on a 6-minute block average. During startup or shutdown, stack opacity shall not exceed 20% based on a 6-minute block average except for one 6-minute block per hour that shall not exceed 27%.	

a. These standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The permit also establishes maximum hourly mass emission rates based on operation at permitted capacity. Compliance with the standards based on stack tests shall be determined by the following EPA stack test methods: NOx (EPA Method 7E); PM (EPA Method 5); SO_2 (EPA Method 6C); VOC (EPA Methods 18 and 25A, as propane); and opacity (EPA Method 9). Compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

b. These standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels and under all load conditions. Compliance with the CO and NOx CEMS-based standards shall be demonstrated by data collected from the required continuous emissions monitoring systems (CEMS) required for these pollutants. The permit allows specific NOx CEMS data to be excluded from the compliance determination (30-day rolling average) when the SNCR system is not functioning due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring. The CO monitor shall meet the applicable requirements in Subpart DDDDD of 40 CFR 63. The NOx monitor shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. An oxygen monitor shall be installed and meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60 to correct the CO and NOx emission rates.

c. NSPS Subpart Db requires a Continuous Opacity Monitoring System (COMS) for new industrial boilers firing "coal, oil, wood or mixtures of these fuels", which applies at all times except startup, shutdown, or malfunction. Therefore, the COMS is required by NSPS Subpart Db when Boiler 8 fires distillate oil alone or in combination with bagasse and/or wood chips. In lieu of the COMS requirements for Boiler 8, EPA Region 4 approved (September 22, 2003) an alternate sampling procedure that includes additional EPA Method 9 observations when firing distillate oil. In addition, the draft permit requires monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP.

d. Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The permit requires the permanent shutdown of Boiler 3 prior to the commercial operation of new Boiler 8.

e. The original PSD permit considered the proposed particulate matter standard for new, large solid fuel fired boilers specified in NESHAP Subpart DDDDD (0.026 lb/MMBtu). The final version of this regulation revised the particulate matter standard to 0.025 lb/MMBtu. For simplicity and clarity, the applicant specifically requested that the BACT standard be reduced to be equivalent to the NESHAP standard. Permit No. PSD-FL-333B revised the standard accordingly.

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original project as well as subsequent revisions.

Good Combustion and Operating Practices

The determination of Best Available Control Technology (BACT) for emissions of carbon monoxide and volatile organic compounds (VOC) from Boiler 8 relied on an efficient boiler design and good combustion and operating practices. To the extent practicable, the permittee shall employ the following procedures to minimize emissions and promote good combustion and pollution control.

Startup and Shutdown

1. Training: All operators and supervisors shall be properly trained to operate and maintain Boiler 8 as well as the pollution control and monitoring equipment in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions during startups, shutdowns, and malfunctions.
2. Boiler Startup: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately ~~4 to 5~~ 6 to 7 hours to reach the desired superheater steam temperature of ~~500~~ 650° F. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. ~~Once this temperature is reached~~ Then, bagasse (and/or wood chips) will be fed until a fire is established across the entire grate. The full steaming rate can be reached about ~~30 to 60 minutes~~ 1 to 3 after first feeding bagasse (and/or wood chips). A boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired.
3. PM Controls: The wet cyclone collectors will be activated before firing any fuel. Prior to activation, the ESP will be purged with ambient air for about 30 to 60 minutes. Distillate oil may be fired during startup prior to energizing the electrostatic precipitator (ESP). The ESP will be on line and functioning properly before any bagasse and/or wood chips are fired. The ESP will remain on line until the bagasse feed has stopped and combustion on the grate is substantially complete.
4. NOx Controls: When the SNCR manufacturer's minimum operating temperature requirement is met, the SNCR system will be activated for NOx control. For a cold startup, this temperature is generally reached within 4 - 5 hours of initial distillate oil firing. During normal operation, the SCNR control system will automatically adjust the urea injection rate and zones to meet the specified NOx standard based on the current urea injection rate, boiler load, furnace temperature, and NOx emissions. During shutdown, the SNCR system shall remain operational until the operating temperature drops below the minimum requirement.
5. Good Combustion Practices: To the extent practicable, the permittee shall maintain the following flue gas levels as indicators of good combustion:
   a. *Oxygen*: The permittee shall install, maintain, and operate a flue gas oxygen monitor on Boiler 8. When firing bagasse during normal operation, the flue gas oxygen content is expected to range from 3% and 4%. High fuel moisture, high ash content, and low load conditions may result in higher flue gas oxygen contents (5% - 6%). When firing only distillate oil, the flue gas exhaust oxygen content is expected to range from 8% and 9% due to tramp air required for cooling of the stoker, pneumatic distributors, and overfire air nozzles. Operators shall ensure that the flue gas oxygen content is sufficient for good combustion.

   b. *Carbon Monoxide (CO)*: Carbon monoxide is an indicator of incomplete fuel combustion. In addition to insufficient oxygen, high fuel moisture, high ash content and low load conditions may result in elevated levels of carbon monoxide. When firing bagasse and/or wood chips during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen. The operator shall use the measured CO emissions at the stack as an indicator of the combustion efficiency and adjust boiler operating conditions as necessary. *{Permitting Note: The stack exhaust is expected to be 1% - 2% (oxygen content) higher than the boiler exhaust due to infiltration from the entire system.}*

   When firing bagasse and/or wood chips, many factors may affect efficient combustion. The above levels represent adherence to good combustion practices under normal operating conditions. Operation outside these levels is not a violation in and of itself. Repeated operation beyond these levels without taking corrective actions to regain good combustion could be considered "circumvention" in accordance with Rule 62-210.650, F.A.C.
6. Boiler Shutdown: To initiate shutdown, the bagasse and/or wood chips fuel feed is terminated. The SNCR systems shall remain functional until operating conditions fall outside of the manufacturer's recommendations. The ~~wet~~ cyclone collectors and ESP shall continue to operate until solid fuel combustion on the fuel grate is substantially complete.

Quarterly CO and NOx Emissions Report

Current Title V Permit No. ______________________

Facility Name	**ARMS ID No.**	**ARMS EU ID No.**
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	0510003	028

Emissions Unit Description

Boiler 8 is a spreader stoker boiler with maximum continuous steam rate of 500,000 lb/hour. Control equipment includes:

- CO/VOC – Efficient combustion design and good operating practices
- NOx – Low NOx oil burners and selective non-catalytic reduction (SNCR) system
- PM/PM10 – Wet cyclone collectors and electrostatic precipitators

Primary Fuel	**Auxiliary Fuels**
Bagasse – Fibrous plant material remaining after sugarcane is milled	Distillate oil (≤ 0.05% sulfur by weight) Wood chips: alternate or supplemental fuel

Year	**Calendar Quarter of Operation Covered** ***(Check one.)***	**Unit Operation in Calendar Quarter**
	___ 1 ___ 2 ___ 3 ___ 4	________ hours

Continuous Emissions Monitoring System (CEMS) Information

Pollutant Monitored: _____ CO _____ NOx Manufacturer: ______________________________

Date of last certification or audit: ____________________ Model No. ______________________________

Emission Data Summary

1. Standard: ________________________________
2. Hours of excess emissions in reporting period due to:
   a. Startup/shutdown .... _____
   b. Control equipment problems .... _____
   c. Process problems .... _____
   d. Other known causes .... _____
   e. Unknown causes .... _____
2. Total hours of excess emissions .... _____
3. (Total hours of excess emissions) / (Total hours of source operating time) x (100%) .... _____

Note: Report "excess emissions" for any emission averages that are in excess of a permitted emissions standard and averaging period.

CEMS Performance Summary

1. Hours of CEMS downtime in reporting period due to:
   a. Monitor equipment malfunctions .... _____
   b. Non-monitor equipment malfunctions .... _____
   c. Quality assurance calibration .... _____
   d. Other known causes .... _____
   e. Unknown causes .... _____
2. Total hours of CEMS downtime .... _____
3. (Total hours of CEMS downtime) / (Total hours of source operating time) x (100%) .... _____

If monitor availability is not at least 95%, provide a report identifying the problems and a plan of corrective actions that will be taken to achieve 95% availability

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startups: _____ c. Malfunctions: _____ e. Total _____
   b. Shutdowns: _____ d. Uncontrolled NOx Monitoring: _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to the CEMS, process equipment, or control equipment during last quarter.

Emission Rates

On a separate page, report the actual emissions for: each rolling 12-month total (tons) of CO emissions for each month in the quarter, and each 30-day rolling NOx average (ppmvd @ 7% oxygen) for each compliance period in the quarter.

Certification

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

Print Name / Title	**Signature / Date**

Shakedown Period

Boiler 8 will be a new type of spreader-stoker specifically designed for the efficient combustion of bagasse and/or wood chips as an alternate or supplemental fuel. Bagasse is the fibrous byproduct remaining from sugarcane after the milling process. The sugarcane milling season runs from October through April. The proposed startup date for the new boiler is January of 2005, which is approximately halfway through the sugarcane milling season. It is expected that a short, initial shakedown period will be necessary for the boiler prior to shakedown of the SNCR system. Although the facility also includes a refinery that operates during the milling off-season, Boiler 8 is not expected to operate much during the off season unless refinery steam demands are high enough to take advantage of large steam production rate from this unit. For these reasons, the Department authorizes the following shakedown period in accordance with the specific conditions, which are in addition to those specified in Section 3 of the permit.

1. Shakedown: Shakedown is limited to the first 360 calendar days after first fire in the boiler and shall not exceed 180 operational days after first fire in the boiler. An "operational day" is any day that Boiler 8 fires any fuel. During shakedown, Boiler 8 shall not operate more than 60 days during the off-season. For this plant, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. Shakedown is complete once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.
2. SNCR System: During the shakedown period, the permittee is authorized to operate the boiler without the SNCR system for purposes of commissioning the boiler and collecting uncontrolled NOx emissions data, provided:
   a. During the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed a total of 240 hours;
   b. After the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed 2 hours each day; and
   c. Notwithstanding the above periods, the operator shall fully utilize the SNCR system to the extent practicable and according to the manufacturer's recommended procedures.
3. CO and NOx CEMS: The CO and NOx CEMS shall be installed and certified within the first 45 operational days of shakedown. CEMS data collected on the first full day following completion of the shakedown period shall be used to begin demonstrating compliance with the CEMS-based emissions standards of the permit.
4. Initial Stack Tests: All initial stack tests required by this permit shall be conducted during the defined shakedown period, but no later than 60 days after achieving the maximum production rate, which is defined as a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average. The permittee shall provide written notification to the Permitting and Compliance Authorities within 10 days of achieving this maximum production rate.

{Permitting Note: After demonstrating compliance and commencing commercial operation, the conditions of Appendix H will become obsolete and need not be included in the Title V air operation permit. The above requirements do not supersede any federal requirements regarding shakedowns for purposes of complying with NSPS or NESHAP regulations. Boiler 8 has a maximum heat input rate greater than 100 MMBtu/hour and is permitted to fire bagasse as the primary fuel, wood chips as an alternate or supplemental fuel, and distillate oil as a startup and supplemental fuel. As such, it is an "affected facility" as defined in NSPS Subpart Db of 40 CFR 60. This NSPS regulates emissions of sulfur dioxide, particulate matter, opacity, and nitrogen oxides for the firing of coal, oil, or natural gas (or mixtures of these fuels with other fuels). However, the NSPS standards for particulate matter and sulfur dioxide are not applicable because the new boiler does not employ add-on controls to reduce sulfur dioxide emissions. Instead, sulfur dioxide emissions are limited by the firing of very low sulfur distillate oil and bagasse and/or wood chips. In turn, the nitrogen oxide emission standard does not apply because the annual capacity factor for the very low sulfur distillate oil is less than 10% as conditioned by the permit. Only opacity is regulated by NSPS Subpart Db for this new boiler when firing distillate oil. Boiler 8 is also subject to the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.}

Incidental Amounts of On-Specification Used Oil with Bagasse and/or Wood Chips

Description

The facility generates small amounts of on-specification used oil consisting mostly of hydraulic fluids and lubrication oils (<< than 10,000 gallons per year). Leaks or spills of these fluids are removed from the work areas by absorbing with bagasse and/or wood chips and then adding to the common biomass conveyor for firing in any of the boilers. The amount of oil is incidental and would not affect emissions.

Requirements

1. Firing: The permittee may fire incidental amounts of bagasse/on-specification oil with other authorized fuels in any of the mill boilers. To the extent practicable, the bagasse/on-specification oil shall be commingled with bagasse and/or wood chips in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C.]
2. Used Oil Specifications: Incidental amounts of used oil to be fired in the boilers shall be on-specification used oil generated on site at this facility. The permittee shall maintain records sufficient to document that the used oil meets the following requirements:
   a. The used oil shall not contain PCBs.
   b. The used oil shall meet the following EPA specifications for "on-specification used oil" in Subpart B of 40 CFR 279:

      Arsenic shall not exceed 5.0 ppm;
      Cadmium shall not exceed 2.0 ppm;
      Chromium shall not exceed 10.0 ppm;
      Lead shall not exceed 100.0 ppm;
      Total halogens shall not exceed 1000.0 ppm; and
      The flash point shall not be less than 100 degrees F.

   Used oil that does not meet the above requirements shall not be burned at this facility. [Rule 62-4.070, F.A.C.; Subpart B, 40 CFR 279]
3. Records: The permittee shall keep records sufficient to document compliance with the above requirements. The records shall be made available when requested by the Compliance Authority. [Rule 62-4.070, F.A.C.]

The following emissions unit is subject to applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63 and adopted by reference in Rule 62-204.800(11), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of ~~500,000~~ 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 63, Subpart A - NESHAP General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the National Emission Standards for Hazardous Air Pollutants including: §63.1 Applicability; §63.2 Definitions; §63.3 Units and abbreviations; §63.4 Prohibited activities and circumvention; §63.5 Preconstruction review and notification requirements; §63.6 Compliance with standards and maintenance requirements; §63.7 Performance testing requirements; §63.8 Monitoring requirements; §63.9 Notification requirements; §63.10 Recordkeeping and reporting requirements; §63.11 Control device requirements;§63.12 State authority and delegations; §63.13 Addresses of State air pollution control agencies and EPA Regional Offices; §63.14 Incorporations by reference; §63.15 Availability of information and confidentiality; §63.16 Performance Track Provisions. The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters

Boiler 8 shall comply with all applicable requirements of Subpart DDDDD in 40 CFR 63, which are adopted by reference in Rule 62-204.800(11), F.A.C. For purposes of this regulation, Boiler 8 is classified as a new, large (> 100 MMBtu/hour), solid fuel (bagasse) industrial boiler. As such, the unit is subject to the following primary requirements:

Pollutant	Emission Limits	Requirements
Particulate Matter (PM)	0.025 lb/MMBtu of heat input	• Surrogate limit for total selected metals (TSM) • Compliance by EPA Method 5 stack test • Compliance test establishes allowable "operating limits" (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • Continuous compliance by continuous monitoring (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • A COMS is not required due to the wet cyclone scrubber
Hydrogen Chloride (HCl)	0.02 lb/MMBtu of heat input	• Compliance by EPA Method 26 or 26A stack test • Monitoring is same as for particulate matter • Scrubber pH monitoring not required (EPA Region 4 letter dated September 4, 2005)
Mercury (Hg)	0.000003 lb/MMBtu of heat input	• Compliance by fuel sampling and analysis methods
Carbon Monoxide (CO)	400 ppmvd @ 7% oxygen (30-day rolling average)	• Surrogate limit for organic HAPs • Compliance by data collected from CO CEMS • CEMS shall be installed, operated and maintained in accordance with the provisions of §63.7525

The following pages contain a table of contents for NESHAP Subpart DDDDD as well as the summary tables from this Subpart that are applicable to Boiler 8.

What This Subpart Covers

63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards

63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

General Compliance Requirements

63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the HCl and TSM standards?

Testing, Fuel Analyses, and Initial Compliance Requirements

63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

Continuous Compliance Requirements

63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

Notifications, Reports, and Records

63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

Other Requirements and Information

63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63

Table 1. Emission Limits and Work Practice Standards
Table 2. Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits
Table 3. Operating Limits for Boilers and Process Heaters with Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4. Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Emission Limits
Table 5. Performance Testing Requirements
Table 6. Fuel Analysis Requirements
Table 7. Establishing Operating Limits
Table 8. Demonstrating Continuous Compliance
Table 9. Reporting Requirements
Table 10. Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD

Appendix A. Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B. Applicability of General Provisions to Subpart DDDDD

TABLE 1. Emission Limits and Work Practice Standards

As stated in §63.7500, Boiler 8 shall comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
1. New Large Solid Fuel	a. Particulate Matter (for Total Selected Metals)	0.025 lb per MMBtu of heat input
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input
	c. Mercury	0.000003 lb per MMBtu of heat input
	d. Carbon Monoxide	400 ppmvd corrected to 7 percent oxygen (30-day rolling average) based on data collected from a CO CEMS

The following provisions cover periods of startup, shutdown, and malfunction.

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §63.7 and §63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §63.7525(a) and §63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §63.6(e) and §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance

with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

TABLE 2. Operating Limits for Boilers with Particulate Matter Emission Limits

As stated in §63.7500, Boiler 8 shall comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet Scrubber Control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
3. Electrostatic Precipitator Control	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

TABLE 4. Operating Limits for Boilers with Hydrogen Chloride Limits

As stated in §63.7500, Boiler 8 shall comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet Scrubber Control	Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 5. Performance Testing Requirements (Particulate Matter and Hydrogen Chloride)

As stated in §63.7520, Boiler 8 shall comply with the following performance test requirements:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure particulate matter emissions concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen Chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).

To conduct a performance test for the following pollutant	You must	Using
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the HCl concentration.	Method 26 or 26A in appendix A to part 60.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

TABLE 6. Fuel Analysis Requirements (Mercury)

As stated in §63.7521, Boiler 8 shall comply with the following fuel analysis testing requirements:

To conduct a fuel analysis for the following pollutant	You must	Using
1. Mercury	a. Collect fuel samples (The permittee notes that samples will be taken from a moving belt.)	Procedure in §63.7521(c) or ASTM D2234-001 (for coal)(IBR, see §63.14(b)) or ASTM D6323-98 (2003)(for biomass)(IBR, see §63.14(b)) or equivalent
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent
	c. Prepare composite fuel samples	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) (IBR, see §63.14(b)) or ASTM D5198-92 (2003) (for biomass)(IBR, see §63.14(b)) or equivalent
	d. Determine heat content of the fuel type	ASTM D5865-03a (for coal)(IBR, see §63.14(b)) or ASTM E711-87 (1996) (for biomass)(IBR, see §63.14(b)) or equivalent
	e. Determine moisture content of the fuel type	ASTM D3173-02 (IBR, see §63.14(b)) or ASTM E871-82 (1998)(IBR, see §63.14(b)) or equivalent
	f. Measure mercury concentration in fuel sample.	ASTM D3684-01 (for coal)(IBR, see §63.14(b)) or SW-846-7471A (for solid samples) or SW-846-7470A (for liquid samples)
	g. Convert concentrations into units of "lb/MMBtu" of heat content.	

TABLE 7. Establishing Operating Limits

As stated in §63.7520, Boiler 8 shall comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
1. Particulate Matter	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests (b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control)	i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c)	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests (b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
				test run

TABLE 8. Demonstrating Continuous Compliance

As stated in §63.7540, Boiler 8 shall show continuous compliance with the emission limitations as follows:

If you must meet the following operating limits or work practice standards	You must demonstrate continuous compliance by
3. Wet Scrubber Pressure Drop and Liquid Flow Rate *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).
6. Precipitator Secondary Current and Voltage or Total Power Input *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §63.7530(c)
7. Fuel Pollutant Content *(For Mercury)*	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to §63.7540(a).

Compliance with the above operating limits and work practice standards demonstrate continuous compliance with the emission limits for PM, HCl, and Hg. A COMS for opacity is not required due to the wet cyclone scrubber. The CO emission limit (400 ppmvd @ 7% oxygen based on a 30-day rolling average) is set as a work practice standard for controlling emissions of organic HAPs. Continuous compliance with the CO limit is demonstrated by data collected with the required CEMS. Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 9. Reporting Requirements

As stated in §63.7550, Boiler 8 shall comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance Report	a. Information required in §63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	Semiannually according to the requirements in §63.7550(b).

You must submit a(n)	The report must contain	You must submit the report
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in §63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Project No. 0510003-037-AC
Air Permit No. PSD-FL-333C

ARMS Facility ID No. 0510003
United States Sugar Corporation
Boiler 8 Capacity Increase

COUNTY

Hendry County, Florida

APPLICANT

United States Sugar Corporation
Clewiston Sugar Mill and Refinery
Intersection of W.C. Owens Avenue and State Road 832
Clewiston, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting North
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

February 2, 2007
(Revised Package)

1. GENERAL PROJECT INFORMATION

Facility Description and Location

U.S. Sugar Corporation operates a sugar mill and refinery in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The UTM coordinates are Zone 17, 506.1 E, and 2956.9 N.

Regulatory Categories

Title III: The plant is a major source of hazardous air pollutants (HAPs).

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

Title V: The plant is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The plant is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the New Source Performance Standards in Subpart Db of 40 CFR 60.

NESHAP: Boiler 8 is subject to the National Emission Standards for HAP in Subpart DDDDD of 40 CFR 63.

Application and Processing Schedule

On June 7, 2006, the Department received an application to modify the PSD air construction permit. For newly constructed Boiler 8, the applicant requests 15% increases in the heat input and steaming rates, clarification of startup procedures, and modification to the biomass fuel handling system. On June 23rd and 26th, the Department requested additional information, which included the requirement to conduct a revised air quality analysis. On September 14th, the Department extended the period of time for the applicant to provide the requested additional information. On October 23rd, the applicant provided the additional information making the application complete.

2. APPLICABLE REGULATIONS

Federal Regulations

The project is subject to applicable federal air quality regulations established by the EPA in the Code of Federal Regulations (CFR). Boiler 8 is currently subject to the New Source Performance Standards (NSPS) for industrial boilers in Subpart Db of 40 CFR 60, which regulates nitrogen oxides, particulate matter, and sulfur dioxide emissions. Boiler 8 is also subject to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for industrial boilers in Subpart DDDDD of 40 CFR 63, which regulates selected metals (or, alternatively, particulate matter), hydrogen chloride, mercury, and carbon monoxide (as a surrogate for organic HAP). The proposed project does not affect the status of Boiler 8 with respect to the existing federal regulations or impose new requirements.

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code as conditioned by Permit No. PSD-FL-333. Specifically, Boiler 8 is subject to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, which required determinations of Best Available Control Technology (BACT) for emissions of nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Therefore, this project requires a PSD applicability analysis, which is provided in the following section.

PSD Applicability Analysis

The Department regulates major stationary sources of air pollution in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) for each regulated pollutant or areas designated as "unclassifiable" for such pollutants. A facility is considered "major" with respect to PSD if it emits or has the potential to emit: ≥ 250 tons per year of any PSD pollutant; or ≥ 100 tons per year of any PSD pollutant and belongs to one of 28 PSD major facility categories; or ≥ 5 tons per year of lead.

For new projects at existing PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the "Significant Emission Rates" defined in Rule 62-212.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and subject to PSD preconstruction review. This means that the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each PSD-significant pollutant as well as evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, the project may be subject to PSD preconstruction review for several PSD-significant pollutants.

For the proposed project, the applicant requests the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8.

- As constructed, the newly designed boiler is capable of firing additional biomass and generating more steam than originally permitted. The applicant requests 15% increases in the short-term heat input and steam production rates. Although this will result in potential increases in hourly emission rates, potential annual emissions will not change because no request is made to increase the permitted annual steam production and heat input rate limitations.
- Based on actual operating data, the applicant requests clarification of the boiler startup procedures and recognition of the possibility of longer startup durations.
- The applicant proposes to modify the existing biomass fuel handling system by installing new landing zones at conveyor transfer points, covering and confining additional conveyor areas, and removing the two installed dust collectors. These improvements are predicted to reduce potential emissions.

The initial startup of Boiler 8 was in March of 2005. Since then, Boiler 8 has had only limited operation in 2005 - 2006 and has not yet established "normal operations" for a 2-year period. As a result, the Department determines the past actual emissions from Boiler 8 to be the potential emissions pursuant to Rule 62-210.200(11), F.A.C. Therefore, the project is not subject to PSD preconstruction review for the determination of BACT. However, the Department required the applicant to conduct a revised Air Quality Analysis with the increased short-term emissions rates to ensure that the project will not result in any adverse air quality impacts.

3. DEPARTMENT REVIEW

Boiler 8 Capacity Increase

The following table summarizes the capacities of Boiler 8 as specified in the current PSD permit and as requested by the applicant for this project.

Table 3A. Current Capacities Compared to Requested Capacities

Parameter	Permit No. PSD-FL-333B	Requested for Project
Design Thermal Efficiency	62%	No Change
Steam Rate, 1-Hour Maximum	550,000	633,000
Steam Rate, 24-Hour Maximum	500,000	575,000
Steam Rate, Annual Maximum	$3.6135 \times 10^{+09}$ pounds/12 months (equivalent to 6,767,100 MMBtu/year)	No Change
Heat Input Rate, 1-Hour Maximum	1030 MMBtu/hour	1185 MMBtu/hour
Heat Input Rate, 24-Hour Maximum	936 MMBtu/hour	1077 MMBtu/hour
Oil Firing Rate, 1-Hour Maximum	4161 gallons/hour	No Change
Oil Firing Rate, Daily Maximum	99,864 gallons/day	No Change
Oil Firing Rate, Annual Maximum	6,073,600 gallons/12 months	No Change

The applicant provided actual operating data from December of 2005 showing that the boiler achieved a maximum 1-hour steam rate of 572,900 lb/hour and a maximum 24-hour steam rate of 525,000 lb/hour, which are approximately 5% above the designed rates. As shown in the above table, the applicant is requesting 15% increases in the currently permitted heat input and steam rates to define the maximum capacity of the unit as constructed. The request will not affect the emissions standards specified in terms of concentrations (ppmvd), mass per heat input (lb/MMBtu), or annual emissions caps (tons/12 months). In addition, it will not result in increased annual potential emissions, which are based on a permit limitation of $3.6135 \times 10^{+09}$ pounds/12 months (equivalent to 6,767,100 MMBtu/year). However, maximum hourly emissions rates will increase as shown in the following table.

Table 3B. Comparison of Emissions Increases for Regulated Pollutants

Pollutant	Process-Based Standards	Maximum Emissions Rates, lb/hour [d]		Annual Potential Emissions
		Current [a]	Requested [b]	Tons/Year [c]
CO	400 ppmvd @ 7% oxygen, 30-day avg.	409.2	470.6	1285
	1285 tons/12 months	---	---	1285
HCl	0.02 lb/MMBtu, 3-hour test	18.7	21.5	67.7
Hg	0.000003 lb/MMBtu, 3-hour test	0.0028	0.0032	0.0102
NO_X	0.14 lb/MMBtu, 30-day avg.	131.0	150.8	473.7
PM	0.025 lb/MMBtu, 3-hour test	23.4	26.9	84.6
SO_2	0.06 lb/MMBtu, 3-hour test	56.2	64.6	203.0
VOC	0.05 lb/MMBtu, 3-hour test	46.8	53.9	169.2

a. As specified in the permit, current hourly emissions rates are based on the maximum 24-hour heat input rate of 936 MMBtu/hour.

b. Requested hourly emissions rates are based on the requested maximum 24-hour heat input rate of 1077 MMBtu/hour.

c. Annual potential emissions are based on the "process-based standards" and the permitted maximum annual heat input rate of 6,767,100 MMBtu/year. Annual potential emissions will not change.

d. For the air quality modeling analysis, higher emissions rates were used for any averaging period of less than 24 hours.

The newly constructed unit has a larger capacity than the original design. There are no physical or operational changes necessary to achieve the higher heat input and steam rates. The increased hourly emissions rates were modeled and showed no adverse ambient impacts. Compliance with the CO and NOx standards are demonstrated with CEMS data. For PM, SO_2, VOC, and opacity, the current permit requires compliance stack tests to be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate. Therefore, the Department will revise the permit to specify that the new boiler capacity will become effective once the permittee satisfactorily demonstrates compliance with the standards for PM, SO_2, VOC, and opacity at the higher capacity.

Boiler 8 Revised Startup Procedures

Appendix F of the PSD permit identifies good combustion and operating practices to minimize emissions of carbon monoxide and volatile organic compounds from Boiler 8 and promote good combustion and pollution control. To the extent practicable, the permittee must employ these practices, which include careful monitoring of oxygen and CO flue gas levels, ensuring sufficient oxygen to promote good combustion, and maintaining the controls for particulate matter and NOx emissions throughout the normal operating ranges of this equipment. The original PSD permit identified the following startup procedure for Boiler 8.

"*Boiler Startup*: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately 4 to 5 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse (and/or wood chips) will be fed until a fire is established across the entire grate. The full steaming rate can be reached about 30 to 60 minutes after first feeding bagasse (and/or wood chips)."

As constructed, the applicant indicates that it is necessary to achieve a superheater steam temperature of 650° F before boiler components reach the desired operating temperatures, which may take up to 6 to 7 hours of firing distillate oil if the boiler is cold. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. Then, biomass is fed until an even fire is established across the entire grate, which can take another 1 to 3 hours to establish the full steaming rate. So, it is possible that a boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired. The applicant requests that the identified startup procedures be revised accordingly.

During startup, boiler conditions are unsteady until a uniform bed of burning biomass is established and process and control equipment achieve normal operating temperatures. To support this statement, the applicant provided actual operating data for four startups from 8 to 11 hours in duration. During the last few hours when transitioning from distillate oil to biomass, operating levels were shown to vary widely before stabilizing. For example, flue gas oxygen levels may swing from 4% to 19% and carbon monoxide levels may spike at over 3000 ppmvd after being less than 200 ppmvd for several hours. Therefore, the Department agrees to revise the description of startup procedures in Appendix F.

To follow up, the Department reviewed the PSD permit to determine whether the revised startup procedures will affect other permit conditions. Because opacity is readily observable and compliance with the standards for CO and NOx is demonstrated by CEMS, the PSD permit currently specifies the following for startup:

Alternate Opacity Standard: "During startup and shutdown, the stack opacity shall not exceed 20% opacity based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity."

CO Emissions: "All valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements." The Subpart DDDDD provisions state, "Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity."

NOx Emissions: "NOx CEMS data collected during startup, shutdown, malfunction, and authorized periods of uncontrolled NOx monitoring may be excluded from the determination of compliance with the 30-day rolling emissions standard, provided:

- Best operational practices are used to minimize emissions; and
- For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional."

Except for the CO emissions cap, the PSD permit conditions currently allow the exclusion of elevated CO and NOx emissions data due to startup provided that best operational practices are used to minimize emissions and the control equipment is placed in service as soon as operating conditions allow. Therefore, no other changes to the permit are necessary.

Biomass Handling System

To control dust from the biomass handling systems, the original project included mostly enclosed conveyors and the installation of five dust collectors to control transfer points. So far, only two dust collectors have been installed because of issues with frequent plugging and high maintenance efforts as well as the associated costs. The applicant has determined that the conveyor transfer points cause unnecessary movement of the conveyor belts, which generates excessive dust. The applicant proposes to modify the existing system by installing new landing zones at conveyor transfer points, covering and confining additional exposed areas, and removing the existing dust collectors.

The new landing zones will provide support for the belts to reduce vibrations and minimize the generation of dust. The conveyor system will now be completely enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The improvements are anticipated to reduce fugitive dust from this system as well as maintenance costs. The application for the original PSD permit estimated approximately 7.5 tons per year of particulate matter from the baghouse exhausts based on the maximum design outlet loadings and the maximum flow rates. Based on standard AP-42 emissions factors, the applicant indicates that the proposed changes will result in potential particulate matter emissions of less than 5 tons per year. The Department approves the changes and will revise the permit accordingly.

Summary of Revisions

The following provides a brief summary of changes to the original PSD permit, as modified:

- *Placard Page*: Update the project description under the "Statement of Basis".
- *Section I, General Information*: Update "Project Description" and "Relevant Documents" list.
- *Section II, Administrative Requirements*: Update revised regulations Conditions 7 and 9.
- *Section III, Subsection A, Boiler 8 (EU-028)*: Update the emissions unit description. Throughout this subsection, revise the heat input and steam production rates. In Conditions 3 and 22, update to include the new dry cyclone authorized in Permit No. 0510003-035-AC. In Condition 7, update the mass emissions rates (lb/hour) based on the revised maximum 24-hour heat input rate. In Condition 14, add the requirement pursuant to Rule 62-297.310(2), F.A.C. that the boiler is limited to 110% of its latest operational rate during compliance testing until new testing is conducted within 90% to 100% of the revised maximum 24-hour heat input rate.
- *Section III, Subsection B, Biomass Handling System (EU-027)*: In Condition 2, update to reflect that the biomass handling system will be modified by installing new landing zones at conveyor transfer points, covering and confining additional exposed areas, and removing the existing dust collectors.
- *Appendix D, NSPS Provisions*: Update emissions unit description for revised steam production rate.
- *Appendix E, Summary of Final BACT Determinations*: Update to reflect the revised heat input and steam production rates, the modified biomass handling system.
- *Appendix F, Good Combustion and Operating Practices*: Update for revised Boiler 8 startup procedures.
- *Appendix J, NESHAP Provisions*: Update emissions unit description for revised steam production rate.

4. AIR QUALITY ANALYSIS

Introduction

Although the project will not increase annual emissions, it will increase maximum short-term emissions. Therefore, the air quality impacts due to the short-term increases were evaluated for the following four pollutants: SO_2, NO_x, PM_{10} and CO. PM_{10}, SO_2 and NO_x are criteria pollutants and have defined national and state ambient air quality standards (AAQS), PSD increments and significant impact levels. CO is a criteria pollutant with only defined AAQS and significant impact levels. A discussion of the required air quality analyses follows.

Models and Meteorological Data Used in the Air Quality Impact Analysis

<u>PSD Class II Area Model</u>

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for annual, 24, 8, 3 and 1-hour averaging periods. A series of specific model features, recommended by the EPA, are referred to as the regulatory options and were used by the applicant. Since some of the associated stacks are less than the good engineering practice (GEP) stack height criteria, the applicant evaluated the potential for building downwash to occur in the air modeling analyses.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at Palm Beach International (PBI) Airport and twice-daily upper air soundings collected at the Florida International University (FIU) in Miami. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

Because five years of data are used in AERMOD, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility and for determining if the project will result in significant impacts in any PSD Class I Area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

PSD Class I Area Model

The nearest PSD Class I area to the Clewiston Mill site is the Everglades National Park (ENP), located about 102 kilometers to the south at its closest point. Since this Class I area is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. 2001 through 2003, 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions changes. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the AAQS or PSD increments. To determine whether there were significant impacts from PM_{10}, SO_2, CO and NOx emissions due to the proposed project, concentrations were predicted using nested Cartesian receptor grids for receptor locations in the Class II area in the vicinity of the project. More than 4,000 receptors located at the Mill's restricted property line and offsite were used. For determining predicted impacts in the ENP PSD Class I area, 251 receptors in the ENP were used.

The tables below show the results of this modeling. Significant impacts were predicted in the Class II area in the vicinity of the project for only SO_2 and for only the 24-hour averaging time. Therefore, further SO_2 AAQS and PSD increment analyses within the predicted significant impact area were required for this project. No significant impacts were predicted in the PSD Class I area; therefore, no further analyses were required in the PSD Class I area.

Maximum Project Air Quality Impacts for Comparison
to PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact
PM_{10}	Annual	0.2	1	No
	24-hour	2.6	5	No
SO_2	Annual	0.5	1	No
	24-hour	6.2	5	Yes
	3-hour	9.3	25	No

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact
NO_x	Annual	0.9	1	No
CO	8-hour	422	500	No
	1-hour	487	2000	No

Maximum Project Air Quality Impacts for Comparison to
PSD Class I Significant Impact Levels in the ENP Class I Area

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact
PM_{10}	Annual	0.001	0.2	No
	24-hour	0.034	0.3	No
SO_2	Annual	0.003	0.1	No
	24-hour	0.080	0.2	No
	3-hour	0.306	1.0	No
NO_x	Annual	0.003	0.1	No

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding "background" concentrations to the maximum modeled concentrations for each pollutant and averaging time. The maximum modeled concentrations are based on the maximum allowable emissions from facility sources and all other sources in the vicinity of the facility. The background concentrations take into account all sources of a particular pollutant that are not explicitly modeled. They are based on recent air quality monitoring data concentrations collected in the vicinity of the project. Even though SO_2 impacts were only significant for the 24-hour averaging period, AAQS impacts were also determined for the 3-hour and annual averaging times. The results of the AAQS analysis for SO_2 are summarized in the table below and show no predicted violations of the AAQS.

Ambient Air Quality Impacts

Pollutant	Averaging Time	Modeled Sources Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)	Total Impact Greater Than AAQS?
SO_2	Annual	8	3	11	60	No
	24-hour	33	5	38	260	No
	3-hour	75	13	88	1,300	No

PSD Class II Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration as established in 1977 for SO_2. The actual baseline year used in this determination was 1975 for existing major sources of SO_2. The emission values that are input into the model for predicting increment consumption are based on maximum potential emissions from increment-consuming facility sources and all other increment-consuming sources in the vicinity of the facility. The maximum predicted PSD Class II area SO_2 increments consumed by this project and all other increment-consuming sources in the vicinity of the facility are shown below. As was done for the AAQS evaluation, maximum 3-hour and annual average SO_2 impacts were also predicted. As shown in the table, there are no predicted impacts greater than the allowable increments.

PSD Class II Increment Analysis

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact > Allowable Increment?
SO_2	Annual	0	20	No
	24-hour	9	91	No
	3-hour	39	512	No

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. An air quality modeling analysis was not required because the project will not result in an increase in emissions. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Cleve Holladay is the staff meteorologist responsible for reviewing and approving the air quality analysis. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

{Filename: PSD-FL-333C Boiler 8 - TEPD}

Adams, Patty

From: Koerner, Jeff

Sent: Wednesday, December 13, 2006 5:13 PM

To: Adams, Patty; Harvey, Mary

Subject: FW: US Sugar Boiler 8 - Capacity Increase

Yes, they called on another subject and I mentioned this one. They had not yet received due to problems with their firewall. it so I sent them just the "PDF" files. As shown below, Don Griffin responded on 12/11/06. Sorry, I should have copied you both.

Jeff

From: Don Griffin [mailto:dgriffin@ussugar.com]
Sent: Monday, December 11, 2006 8:41 AM
To: Koerner, Jeff; Peter Briggs
Cc: dave_buff@golder.com; Neil Smith
Subject: RE: US Sugar Boiler 8 - Capacity Increase

Jeff
Thanks.

Received the PDF files – we don't seem to be able to get zipped files past security..
Thanks again
Hope you and your family have a happy holiday season

From: Koerner, Jeff [mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Monday, December 11, 2006 8:28 AM
To: Peter Briggs; Don Griffin
Cc: dave_buff@golder.com; Neil Smith
Subject: US Sugar Boiler 8 - Capacity Increase

Peter and Don,

Our secretary emailed the "zipped" files last Thursday. I know Dave Buff received the email, but if I remember correctly, US Sugar's firewall does not allow zipped files through. So, here are the individual PDF files. I am also including a MS Word version of the Public Notice. Please call if you have any questions.

Thanks!

Jeff Koerner, BAR - Air Permitting North
Florida Department of Environmental Protection
850/921-9536

<<PSD-FL-333C Boiler 8 - Intent - #0510003-037-AC-DRAFT.PDF>> <<PSD-FL-333C Boiler 8 - Draft Permit - #0510003-037-AC- DRAFT.PDF>> <<PSD-FL-333C Boiler 8 - Appendix- #0510003-037-AC-DRAFT.PDF>> <<PSD-FL-333C Boiler 8 - TEPD - #0510003-037-AC-DRAFT.PDF>> <<Signed Certificate and Cover Letter - 0510003-AC-DRAFT.pdf>> <<PSD-FL-333C Boiler 8 - Public Notice Only.doc>>

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,
DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:10 PM
To: 'NSMITH@USSUGAR.COM'; 'PBRIGGS@USSUGAR.COM'; 'DGRIFFIN@USSUGAR.COM'; 'dave_buff@golder.com'; Blackburn, Ron; 'worley.gregg@epa.gov'; 'john_bunyak@nps.gov'
Cc: Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC
Attachments: 0510003.037.AC.D_pdf.zip

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:45 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

From: Buff, Dave [mailto:DBuff@GOLDER.com]
Sent: Thursday, December 07, 2006 4:25 PM
Subject: Read: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

Your message

To: DBuff@GOLDER.com
Subject:

was read on 12/7/2006 4:25 PM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:17 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

From: Blackburn, Ron
Sent: Thursday, December 07, 2006 4:13 PM
To: Harvey, Mary
Subject: Read: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

Your message

To:	'NSMITH@USSUGAR.COM'; 'PBRIGGS@USSUGAR.COM'; 'DGRIFFIN@USSUGAR.COM'; 'dave_buff@golder.com'; Blackburn, Ron; 'worley.gregg@epa.gov'; 'john_bunyak@nps.gov'
Cc:	Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject:	Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC
Sent:	12/7/2006 4:10 PM

was read on 12/7/2006 4:13 PM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 07, 2006 4:16 PM
To: Koerner, Jeff; Adams, Patty
Subject: FW: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

-----Original Message-----
From: John_Bunyak@nps.gov [mailto:John_Bunyak@nps.gov]
Sent: Thursday, December 07, 2006 4:14 PM
To: Harvey, Mary
Subject: Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC

Return Receipt

Your document:	Sugar Processing Operations - Clewiston Sugal Mill and Refinery #0510003-037-AC
was received by:	John Bunyak/DENVER/NPS
at:	12/07/2006 02:14:00 PM

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

December 7, 2006

(Sent by Electronic Mail – Return Receipt Requested)

Neil Smith, Vice President and General Manager
Sugar Processing Operations - Clewiston Sugar Mill and Refinery
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Re: Draft Air Construction Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler No. 8 Capacity Increase

Dear Mr. Smith:

U.S. Sugar Corporation submitted an application for the existing Clewiston Sugar Mill and Refinery requesting the following for newly constructed Boiler 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. The application was made complete with the additional information provided on October 23, 2006. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

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

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

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection

Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
U.S. Sugar Corporation – Clewiston Sugar Mill and Refinery
Hendry County, Florida

Applicant: The applicant for this project is the U.S. Sugar Corporation. The applicant's authorized representative and mailing address is: Mr. Neil Smith, Vice President and General Manager of Sugar Processing Operations, U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, Florida 33440.

Facility Location: U.S. Sugar Corporation operates an existing sugar mill and refinery, which is located in Hendry County at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: Boiler 8 was originally permitted as a major modification in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality. Subsequent projects must be reviewed for PSD applicability. The applicant proposes the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8: clarification of boiler startup procedures; modification of the biomass fuel handling system; and increases in the heat input and steaming rates. As constructed, this newly designed boiler is actually capable of generating 15% more steam when firing approximately 15% more fuel. Although this will result in potential increases in hourly emission rates, annual potential emissions will not increase because there will be no change in the current limitation on the annual steam production. Initial startup of Boiler 8 was March of 2005. This unit has not established normal operations for a two-year period. Pursuant to Rule 62-210.200(11), F.A.C., there will be no increase in annual emissions and the project is not subject to PSD preconstruction review.

Because the project results in increased potential maximum short-term emissions, an air quality impact analysis was conducted for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter less than 10 microns in diameter (PM_{10}), and sulfur dioxide (SO_2). For these pollutants, the initial air dispersion modeling analysis predicted ambient concentrations below the applicable PSD significant impact levels for the closest PSD Class I Area, which is the Everglades National Park. The initial air dispersion modeling analysis also predicted ambient concentrations below the applicable PSD significant impact levels for the PSD Class II Areas in the vicinity of the plant, except for the 24-hour average SO_2 value. Therefore, a refined analysis was conducted for SO_2 emissions. The subsequent modeling results showed all predicted SO_2 emissions impacts well below the applicable state and federal ambient air quality standards. The following table compares the total maximum impacts predicted in the area with the corresponding maximum allowable PSD Class II increments.

Pollutant	Averaging Time	Total Maximum Impacts ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed
SO_2	Annual	0	20	0%
	24-hour	9	91	10%
	3-hour	39	512	8%

As shown by the air quality analyses, emissions from the modified project will not significantly cause or contribute to a violation of any state or federal ambient air quality standards or PSD increments.

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

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

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

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available for this proceeding.

(Public Notice to be Published in the Newspaper)

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Mr. Neil Smith, V.P. and General Manager
Sugar Processing Operations - Clewiston Sugar Mill and Refinery
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Clewiston Sugar Mill and Refinery
Boiler 8 Capacity Increase
Hendry County, Florida

Facility Location: U.S. Sugar Corporation (applicant) operates an existing sugar mill and refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida.

Project: The applicant proposed the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. Details of the project are provided in the in the application and the enclosed "Technical Evaluation and Preliminary Determination".

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

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

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

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

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by electronic mail (with return receipt requested) before the close of business on 12/7/06 to the persons listed below.

Mr. Neil Smith, U.S. Sugar (nsmith@ussugar.com)
Mr. Peter Briggs, U.S. Sugar (pbriggs@ussugar.com)
Mr. Don Griffin, U.S. Sugar (dgriffin@ussugar.com)
Mr. David Buff, Golder Associates (dave_buff@golder.com)
Mr. Ron Blackburn, SD Office (blackburn_r@dep.state.fl.us)
Mr. Gregg Worley, EPA Region 4 (worley.gregg@epamail.epa.gov)
Mr. John Bunyak (john_bunyak@nps.gov)

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.

Mary L Harvey 12/7/06

(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

FROM: Jeff Koerner, Air Permitting North

DATE: November 30, 2006

SUBJECT: Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
U.S. Sugar Corporation - Clewiston Sugar Mill and Refinery
Boiler 8 Capacity Increase

U.S. Sugar Corporation submitted an application for the existing Clewiston Sugar Mill and Refinery requesting the following for newly constructed Boiler 8: increases in the heat input and steaming rates; clarification of startup procedures; and modification to the biomass fuel handling system. Attached for your review are the Intent to Issue Permit and Public Notice Package including the Technical Evaluation and Preliminary Determination, modified Draft Permit, and P.E. Certification. I recommend your approval of the attached Draft Permit for this project. "Day 74" is January 4, 2007.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Draft Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Boiler 8 Capacity Increase

PROJECT DESCRIPTION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), which is located Hendry County, Florida. Boiler 8 is newly constructed in accordance with PSD air construction Permit No. PSD-FL-333. U.S. Sugar submitted an application for the following changes: clarification of startup procedures, modifications of the biomass fuel handling system, and 15% increases in the heat input and steaming rates for the boiler as constructed. Boiler 8 had only limited operation in 2005 - 2006 and has not yet established "normal operations" for a 2-year period. As a result, the Department considers the past actual emissions from Boiler 8 to be the permitted potential emissions. Although maximum short-term emissions rates will increase, annual potential emissions remain restricted by the permit limitation on annual steam production. Therefore, the project is not subject to PSD preconstruction review. However, a revised air quality analysis was conducted, which confirmed that the increased short-term emissions rates will not cause adverse ambient impacts.

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

Jeffery F. Koerner 12-7-06

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

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Project No. 0510003-037-AC
Air Permit No. PSD-FL-333C

ARMS Facility ID No. 0510003
United States Sugar Corporation
Boiler 8 Capacity Increase

COUNTY

Hendry County, Florida

APPLICANT

United States Sugar Corporation
Clewiston Sugar Mill and Refinery
Intersection of W.C. Owens Avenue and State Road 832
Clewiston, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting North
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

December 7, 2006

1. GENERAL PROJECT INFORMATION

Facility Description and Location

U.S. Sugar Corporation operates a sugar mill and refinery in Clewiston at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The UTM coordinates are Zone 17, 506.1 E, and 2956.9 N.

Regulatory Categories

Title III: The plant is a major source of hazardous air pollutants (HAPs).

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

Title V: The plant is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The plant is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the New Source Performance Standards in Subpart Db of 40 CFR 60.

NESHAP: Boiler 8 is subject to the National Emission Standards for HAP in Subpart DDDDD of 40 CFR 63.

Application and Processing Schedule

On June 7, 2006, the Department received an application to modify the PSD air construction permit. For newly constructed Boiler 8, the applicant requests 15% increases in the heat input and steaming rates, clarification of startup procedures, and modification to the biomass fuel handling system. On June 23rd and 26th, the Department requested additional information, which included the requirement to conduct a revised air quality analysis. On September 14th, the Department extended the period of time for the applicant to provide the requested additional information. On October 23rd, the applicant provided the additional information making the application complete.

2. APPLICABLE REGULATIONS

Federal Regulations

The project is subject to applicable federal air quality regulations established by the EPA in the Code of Federal Regulations (CFR). Boiler 8 is currently subject to the New Source Performance Standards (NSPS) for industrial boilers in Subpart Db of 40 CFR 60, which regulates nitrogen oxides, particulate matter, and sulfur dioxide emissions. Boiler 8 is also subject to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for industrial boilers in Subpart DDDDD of 40 CFR 63, which regulates selected metals (or, alternatively, particulate matter), hydrogen chloride, mercury, and carbon monoxide (as a surrogate for organic HAP). The proposed project does not affect the status of Boiler 8 with respect to the existing federal regulations or impose new requirements.

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code as conditioned by Permit No. PSD-FL-333. Specifically, Boiler 8 is subject to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, which required determinations of Best Available Control Technology (BACT) for emissions of nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Therefore, this project requires a PSD applicability analysis, which is provided in the following section.

PSD Applicability Analysis

The Department regulates major stationary sources of air pollution in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) for each regulated pollutant or areas designated as "unclassifiable" for such pollutants. A facility is considered "major" with respect to PSD if it emits or has the potential to emit: ≥ 250 tons per year of any PSD pollutant; or ≥ 100 tons per year of any PSD pollutant and belongs to one of 28 PSD major facility categories; or ≥ 5 tons per year of lead.

For new projects at existing PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the "Significant Emission Rates" defined in Rule 62-212.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and subject to PSD preconstruction review. This means that the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each PSD-significant pollutant as well as evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, the project may be subject to PSD preconstruction review for several PSD-significant pollutants.

For the proposed project, the applicant requests the following revisions to Permit No. PSD-FL-333 for newly constructed Boiler No. 8.

- As constructed, the newly designed boiler is capable of firing additional biomass and generating more steam than originally permitted. The applicant requests 15% increases in the short-term heat input and steam production rates. Although this will result in potential increases in hourly emission rates, potential annual emissions will not change because no request is made to increase the permitted annual steam production and heat input rate limitations.
- Based on actual operating data, the applicant requests clarification of the boiler startup procedures and recognition of the possibility of longer startup durations.
- The applicant proposes to modify the existing biomass fuel handling system by installing new landing zones at conveyor transfer points, covering and confining additional conveyor areas, and removing the two installed dust collectors. These improvements are predicted to reduce potential emissions.

The initial startup of Boiler 8 was in March of 2005. Since then, Boiler 8 has had only limited operation in 2005 - 2006 and has not yet established "normal operations" for a 2-year period. As a result, the Department determines the past actual emissions from Boiler 8 to be the potential emissions pursuant to Rule 62-210.200(11), F.A.C. Therefore, the project is not subject to PSD preconstruction review for the determination of BACT. However, the Department required the applicant to conduct a revised Air Quality Analysis with the increased short-term emissions rates to ensure that the project will not result in any adverse air quality impacts.

3. DEPARTMENT REVIEW

Boiler 8 Capacity Increase

The following table summarizes the capacities of Boiler 8 as specified in the current PSD permit and as requested by the applicant for this project.

Table 3A. Current Capacities Compared to Requested Capacities

Parameter	Permit No. PSD-FL-333B	Requested for Project
Design Thermal Efficiency	62%	No Change
Steam Rate, 1-Hour Maximum	550,000	633,000
Steam Rate, 24-Hour Maximum	500,000	575,000
Steam Rate, Annual Maximum	$3.6135 \times 10^{+09}$ pounds/12 months (equivalent to 6,767,100 MMBtu/year)	No Change
Heat Input Rate, 1-Hour Maximum	1030 MMBtu/hour	1185 MMBtu/hour
Heat Input Rate, 24-Hour Maximum	936 MMBtu/hour	1077 MMBtu/hour
Oil Firing Rate, 1-Hour Maximum	4161 gallons/hour	No Change
Oil Firing Rate, Daily Maximum	99,864 gallons/day	No Change
Oil Firing Rate, Annual Maximum	6,073,600 gallons/12 months	No Change

The applicant provided actual operating data from December of 2005 showing that the boiler achieved a maximum 1-hour steam rate of 572,900 lb/hour and a maximum 24-hour steam rate of 525,000 lb/hour, which are approximately 5% above the designed rates. As shown in the above table, the applicant is requesting 15% increases in the currently permitted heat input and steam rates to define the maximum capacity of the unit as constructed. The request will not affect the emissions standards specified in terms of concentrations (ppmvd), mass per heat input (lb/MMBtu), or annual emissions caps (tons/12 months). In addition, it will not result in increased annual potential emissions, which are based on a permit limitation of $3.6135 \times 10^{+09}$ pounds/12 months (equivalent to 6,767,100 MMBtu/year). However, maximum hourly emissions rates will increase as shown in the following table.

Table 3B. Comparison of Emissions Increases for Regulated Pollutants

Pollutant	Process-Based Standards	Maximum Emissions Rates, lb/hour [d]		Annual Potential Emissions
		Current [a]	Requested [b]	Tons/Year [c]
CO	400 ppmvd @ 7% oxygen, 30-day avg.	409.2	470.6	1285
	1285 tons/12 months	---	---	1285
HCl	0.02 lb/MMBtu, 3-hour test	18.7	21.5	67.7
Hg	0.000003 lb/MMBtu, 3-hour test	0.0028	0.0032	0.0102
NO_X	0.14 lb/MMBtu, 30-day avg.	131.0	150.8	473.7
PM	0.025 lb/MMBtu, 3-hour test	23.4	26.9	84.6
SO_2	0.06 lb/MMBtu, 3-hour test	56.2	64.6	203.0
VOC	0.05 lb/MMBtu, 3-hour test	46.8	53.9	169.2

a. As specified in the permit, current hourly emissions rates are based on the maximum 24-hour heat input rate of 936 MMBtu/hour.

b. Requested hourly emissions rates are based on the requested maximum 24-hour heat input rate of 1077 MMBtu/hour.

c. Annual potential emissions are based on the "process-based standards" and the permitted maximum annual heat input rate of 6,767,100 MMBtu/year. Annual potential emissions will not change.

d. For the air quality modeling analysis, higher emissions rates were used for any averaging period of less than 24 hours.

The newly constructed unit has a larger capacity than the original design. There are no physical or operational changes necessary to achieve the higher heat input and steam rates. The increased hourly emissions rates were modeled and showed no adverse ambient impacts. Compliance with the CO and NOx standards are demonstrated with CEMS data. For PM, SO_2, VOC, and opacity, the current permit requires compliance stack tests to be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate. Therefore, the Department will revise the permit to specify that the new boiler capacity will become effective once the permittee satisfactorily demonstrates compliance with the standards for PM, SO_2, VOC, and opacity at the higher capacity.

Boiler 8 Revised Startup Procedures

Appendix F of the PSD permit identifies good combustion and operating practices to minimize emissions of carbon monoxide and volatile organic compounds from Boiler 8 and promote good combustion and pollution control. To the extent practicable, the permittee must employ these practices, which include careful monitoring of oxygen and CO flue gas levels, ensuring sufficient oxygen to promote good combustion, and maintaining the controls for particulate matter and NOx emissions throughout the normal operating ranges of this equipment. The original PSD permit identified the following startup procedure for Boiler 8.

"*Boiler Startup*: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately 4 to 5 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse (and/or wood chips) will be fed until a fire is established across the entire grate. The full steaming rate can be reached about 30 to 60 minutes after first feeding bagasse (and/or wood chips)."

As constructed, the applicant indicates that it is necessary to achieve a superheater steam temperature of 650° F before boiler components reach the desired operating temperatures, which may take up to 6 to 7 hours of firing distillate oil if the boiler is cold. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. Then, biomass is fed until an even fire is established across the entire grate, which can take another 1 to 3 hours to establish the full steaming rate. So, it is possible that a boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired. The applicant requests that the identified startup procedures be revised accordingly.

During startup, boiler conditions are unsteady until a uniform bed of burning biomass is established and process and control equipment achieve normal operating temperatures. To support this statement, the applicant provided actual operating data for four startups from 8 to 11 hours in duration. During the last few hours when transitioning from distillate oil to biomass, operating levels were shown to vary widely before stabilizing. For example, flue gas oxygen levels may swing from 4% to 19% and carbon monoxide levels may spike at over 3000 ppmvd after being less than 200 ppmvd for several hours. Therefore, the Department agrees to revise the description of startup procedures in Appendix F.

To follow up, the Department reviewed the PSD permit to determine whether the revised startup procedures will affect other permit conditions. Because opacity is readily observable and compliance with the standards for CO and NOx is demonstrated by CEMS, the PSD permit currently specifies the following for startup:

Alternate Opacity Standard: "During startup and shutdown, the stack opacity shall not exceed 20% opacity based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity."

CO Emissions: "All valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements." The Subpart DDDDD provisions state, "Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity."

NOx Emissions: "NOx CEMS data collected during startup, shutdown, malfunction, and authorized periods of uncontrolled NOx monitoring may be excluded from the determination of compliance with the 30-day rolling emissions standard, provided:

- Best operational practices are used to minimize emissions; and
- For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional."

Except for the CO emissions cap, the PSD permit conditions currently allow the exclusion of elevated CO and NOx emissions data due to startup provided that best operational practices are used to minimize emissions and the control equipment is placed in service as soon as operating conditions allow. Therefore, no other changes to the permit are necessary.

Biomass Handling System

To control dust from the biomass handling systems, the original project included mostly enclosed conveyors and the installation of five dust collectors to control transfer points. So far, only two dust collectors have been installed because of issues with frequent plugging and high maintenance efforts as well as the associated costs. The applicant has determined that the conveyor transfer points cause unnecessary movement of the conveyor belts, which generates excessive dust. The applicant proposes to modify the existing system by installing new landing zones at conveyor transfer points, covering and confining additional exposed areas, and removing the existing dust collectors.

The new landing zones will provide support for the belts to reduce vibrations and minimize the generation of dust. The conveyor system will now be completely enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The improvements are anticipated to reduce fugitive dust from this system as well as maintenance costs. The application for the original PSD permit estimated approximately 7.5 tons per year of particulate matter from the baghouse exhausts based on the maximum design outlet loadings and the maximum flow rates. Based on standard AP-42 emissions factors, the applicant indicates that the proposed changes will result in potential particulate matter emissions of less than 5 tons per year. The Department approves the changes and will revise the permit accordingly.

Summary of Revisions

The following provides a brief summary of changes to the original PSD permit, as modified:

- *Placard Page*: Update the project description under the "Statement of Basis".
- *Section I, General Information*: Update "Project Description" and "Relevant Documents" list.
- *Section II, Administrative Requirements*: Update revised regulations Conditions 7 and 9.
- *Section III, Subsection A, Boiler 8 (EU-028)*: Update the emissions unit description. Throughout this subsection, revise the heat input and steam production rates. In Conditions 3 and 22, update to include the new dry cyclone authorized in Permit No. 0510003-035-AC. In Condition 7, update the mass emissions rates (lb/hour) based on the revised maximum 24-hour heat input rate. In Condition 14, add the requirement pursuant to Rule 62-297.310(2), F.A.C. that the boiler is limited to 110% of its latest operational rate during compliance testing until new testing is conducted within 90% to 100% of the revised maximum 24-hour heat input rate.
- *Section III, Subsection B, Biomass Handling System (EU-027)*: In Condition 2, update to reflect that the biomass handling system will be modified by installing new landing zones at conveyor transfer points, covering and confining additional exposed areas, and removing the existing dust collectors. In Conditions 3 and 4, update to include the existing bagacillo cyclone as a unit regulated for opacity.
- *Appendix D, NSPS Provisions*: Update emissions unit description for revised steam production rate.
- *Appendix E, Summary of Final BACT Determinations*: Update to reflect the revised heat input and steam production rates, the modified biomass handling system, and the existing bagacillo cyclone.
- *Appendix F, Good Combustion and Operating Practices*: Update for revised Boiler 8 startup procedures.
- *Appendix J, NESHAP Provisions*: Update emissions unit description for revised steam production rate.

4. AIR QUALITY ANALYSIS

Introduction

Although the project will not increase annual emissions, it will increase maximum short-term emissions. Therefore, the air quality impacts due to the short-term increases were evaluated for the following four pollutants: SO_2, NO_x, PM_{10} and CO. PM_{10}, SO_2 and NO_x are criteria pollutants and have defined national and state ambient air quality standards (AAQS), PSD increments and significant impact levels. CO is a criteria pollutant with only defined AAQS and significant impact levels. A discussion of the required air quality analyses follows.

Models and Meteorological Data Used in the Air Quality Impact Analysis

PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for annual, 24, 8, 3 and 1-hour averaging periods. A series of specific model features, recommended by the EPA, are referred to as the regulatory options and were used by the applicant. Since some of the associated stacks are less than the good engineering practice (GEP) stack height criteria, the applicant evaluated the potential for building downwash to occur in the air modeling analyses.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at Palm Beach International (PBI) Airport and twice-daily upper air soundings collected at the Florida International University (FIU) in Miami. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

Because five years of data are used in AERMOD, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility and for determining if the project will result in significant impacts in any PSD Class I Area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

PSD Class I Area Model

The nearest PSD Class I area to the Clewiston Mill site is the Everglades National Park (ENP), located about 102 kilometers to the south at its closest point. Since this Class I area is greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. 2001 through 2003, 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions changes. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the AAQS or PSD increments. To determine whether there were significant impacts from PM_{10}, SO_2, CO and NOx emissions due to the proposed project, concentrations were predicted using nested Cartesian receptor grids for receptor locations in the Class II area in the vicinity of the project. More than 4,000 receptors located at the Mill's restricted property line and offsite were used. For determining predicted impacts in the ENP PSD Class I area, 251 receptors in the ENP were used.

The tables below show the results of this modeling. Significant impacts were predicted in the Class II area in the vicinity of the project for only SO_2 and for only the 24-hour averaging time. Therefore, further SO_2 AAQS and PSD increment analyses within the predicted significant impact area were required for this project. No significant impacts were predicted in the PSD Class I area; therefore, no further analyses were required in the PSD Class I area.

Maximum Project Air Quality Impacts for Comparison
to PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Significant Impact Level (μg/m^3)	Significant Impact
PM_{10}	Annual	0.2	1	No
	24-hour	2.6	5	No
SO_2	Annual	0.5	1	No
	24-hour	6.2	5	Yes
	3-hour	9.3	25	No

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Significant Impact Level (μg/m^3)	Significant Impact
NO_x	Annual	0.9	1	No
CO	8-hour	422	500	No
	1-hour	487	2000	No

Maximum Project Air Quality Impacts for Comparison to
PSD Class I Significant Impact Levels in the ENP Class I Area

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Significant Impact Level (μg/m^3)	Significant Impact
PM_{10}	Annual	0.001	0.2	No
	24-hour	0.034	0.3	No
SO_2	Annual	0.003	0.1	No
	24-hour	0.080	0.2	No
	3-hour	0.306	1.0	No
NO_x	Annual	0.003	0.1	No

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding "background" concentrations to the maximum modeled concentrations for each pollutant and averaging time. The maximum modeled concentrations are based on the maximum allowable emissions from facility sources and all other sources in the vicinity of the facility. The background concentrations take into account all sources of a particular pollutant that are not explicitly modeled. They are based on recent air quality monitoring data concentrations collected in the vicinity of the project. Even though SO_2 impacts were only significant for the 24-hour averaging period, AAQS impacts were also determined for the 3-hour and annual averaging times. The results of the AAQS analysis for SO_2 are summarized in the table below and show no predicted violations of the AAQS.

Ambient Air Quality Impacts

Pollutant	Averaging Time	Modeled Sources Impact (μg/m^3)	Background Concentration (μg/m^3)	Total Impact (μg/m^3)	Florida AAQS (μg/m^3)	Total Impact Greater Than AAQS?
SO_2	Annual	8	3	11	60	No
	24-hour	33	5	38	260	No
	3-hour	75	13	88	1,300	No

PSD Class II Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration as established in 1977 for SO_2. The actual baseline year used in this determination was 1975 for existing major sources of SO_2. The emission values that are input into the model for predicting increment consumption are based on maximum potential emissions from increment-consuming facility sources and all other increment-consuming sources in the vicinity of the facility. The maximum predicted PSD Class II area SO_2 increments consumed by this project and all other increment-consuming sources in the vicinity of the facility are shown below. As was done for the AAQS evaluation, maximum 3-hour and annual average SO_2 impacts were also predicted. As shown in the table, there are no predicted impacts greater than the allowable increments.

PSD Class II Increment Analysis

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact > Allowable Increment?
SO_2	Annual	0	20	No
	24-hour	9	91	No
	3-hour	39	512	No

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. An air quality modeling analysis was not required because the project will not result in an increase in emissions. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Cleve Holladay is the staff meteorologist responsible for reviewing and approving the air quality analysis. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

{Filename: PSD-FL-333C Boiler 8 - TEPD}

PERMITTEE:

United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440
Authorized Representative:
Mr. William A. Raiola, V.P. of Sugar Processing Operations

Clewiston Sugar Mill and Refinery
Air Permit No. PSD-FL-333C
Project No. 0510003-037-AC
Facility ID No. 0510003
Permit Expires: {Date}

FACILITY AND LOCATION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery (SIC Nos. 2061 and 2062), which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery.

STATEMENT OF BASIS

Boiler 8 was recently constructed under Permit No. PSD-FL-333, as modified. This permitting action is a revision of the air construction permit to specifically address the following items for this unit: increases in the heat input and steaming rates; clarification of startup procedures; and modification of the biomass fuel handling system. The revised 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 perform the proposed work in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

DRAFT

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

PROJECT DESCRIPTION

Boiler 8 (EU-028) is a new spreader-stoker boiler with a maximum heat input rate of ~~1030~~ 1185 MMBtu per hour. It will fire bagasse as the primary fuel and wood chips as an alternate or supplemental fuel. Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Air pollution control equipment includes a ~~wet~~ cyclone/electrostatic precipitator (ESP) combination to remove particulate matter and a selective non-catalytic reduction system (SNCR) to reduce nitrogen oxides. Good combustion design and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Low sulfur fuels (i.e., bagasse, wood chips, and distillate oil) will be used to minimize potential emissions of sulfuric acid mist and sulfur dioxide. Monitoring equipment will continuously monitor and record emissions of carbon monoxide and nitrogen oxides. To minimize fugitive particulate matter from the biomass handling system (EU-027), biomass conveyors will be enclosed and new landing zones ~~dust collectors~~ installed on conveyor transfer points.

REGULATORY CLASSIFICATION

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

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

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major facility as defined in Rule 62-212.400, F.A.C.

NSPS: Boiler 8 is subject to the applicable New Source Performance Standards in Subpart Db of 40 CFR 60.

NESHAP: Boiler 8 is subject to the applicable National Emissions Standards for HAP in Subpart DDDDD of 40 CFR 63.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Formats
Appendix B. General Conditions
Appendix C. Common Requirements
Appendix D. NSPS Provisions
Appendix E. Summary of Final BACT Determinations
Appendix F. Good Combustion and Operating Practices
Appendix G. Quarterly CO and NOx Emissions Report
Appendix H. Shakedown Period
Appendix I. **Incidental Amounts of On-Specification Used Oil with Bagasse**
Appendix J. NESHAP Provisions

RELEVANT DOCUMENTS

The applications, correspondence, and permits related to the following projects are considered relevant documents: original Project No. 0510003-021-AC (PSD-FL-333), revised Project No. 0510003-024-AC (PSD-FL-333A), Project No. 0510003-030-AC (PSD-FL-333B), and Project No. 0510003-037-AC (PSD-FL-333C). Relevant documents are not a part of this permit, but include information specifically related to this permitting action and are on file with the Department.

1. Permitting Authority: All documents related to PSD applications for permits to construct or modify emissions units shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of each application shall be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.

3. Rule Citations: Appendix A of this permit explains the methods used to cite rules, regulations, and permits.

4. General Conditions: The permittee shall comply with the general conditions specified in Appendix B of this permit. [Rule 62-4.160, F.A.C.]

5. Common Requirements: The permittee shall comply with the common regulatory requirements specified in Appendix C of this permit. [Chapters 62-4, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.]

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

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(12)(a)~~(6)(b)~~, F.A.C.; 40 CFR 52.21(r)(2); 40 CFR 51.166(j)(4)]

8. 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.]

~~9. Relaxations of Restrictions on Pollutant Emitting Capacity. If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7,1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it. [Rule 62-212.400(2)(g), F.A.C.]~~

9. Source Obligation: 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. [Rule 62-212.400(12)(b), F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rule 62-4.030 and Chapters 62-210 and 62-212, F.A.C.]

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

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

ID	Emission Unit Description
028	*Description*: Boiler 8 will be a membrane wall boiler with balanced draft stoker, overfire air, rotating feeders, and pneumatic spreaders. It will be designed to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. *Fuels*: The primary fuel will be bagasse (SCC No. 1-02-011-01). Wood chips will be fired as an alternate or supplemental fuel (SCC No. 1-02-009-02). Distillate oil (SCC No. 1-02-005-01) containing no more than 0.05% sulfur by weight will be fired as a restricted alternate fuel for startup and supplemental uses. *Capacity*: The maximum continuous steam production is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour averages). *Controls*: Particulate matter is controlled by ~~wet~~ cyclone collectors followed by an electrostatic precipitator (ESP). Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used to minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. *Stack Parameters*: The stack will be 13.0 feet in diameter (maximum) and 199 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of ~~330~~ 315° F and a volumetric flow rate of ~~400,000~~ 395,000 acfm at ~~5.5~~ 7% oxygen (~~225,000~~ 270,000 dscfm at 7% oxygen). *CEMS*: Emissions of carbon monoxide and nitrogen oxides will be monitored and recorded by continuous emissions monitoring systems (CEMS).

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions of nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC). Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The final BACT determinations are presented in Appendix E of this permit. Boiler 8 is also subject to the following applicable requirements: Rule 62-296.405, F.A.C. (fossil fuel fired steam generators with more than 250 MMBtu per hour of heat input); Rule 62-296.410, F.A.C. (carbonaceous fuel burning equipment); the federal New Source Performance Standards (NSPS) of Subpart Db (industrial boilers) in 40 CFR 60, which is adopted by reference in Rule 62-204.800(8), F.A.C.; and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) of Subpart DDDDD (industrial boilers) in 40 CFR 63, which is adopted by reference in Rule 62-204.800(11), F.A.C.}

EQUIPMENT

1. Shutdown of Boiler 3: No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of first fire in Boiler 8. Shakedown of the boiler is defined in Appendix H of this permit. During the authorized shakedown period:
   a. Boiler 8 may operate with the other existing boilers to ensure proper integration with the sugar mill and refinery. Any fuel oil fired in Boilers 1, 2, and 3 shall contain no more than 1.6% sulfur by weight.
   b. Boilers 3 and 8 may operate concurrently for no more than 90 individual days during which the combined steam production from Boilers 3 and 8 shall not exceed a daily average of 250,000 pounds per hour. After first fire and shakedown of Boiler 8, Boiler 3 shall be permanently shutdown prior to commencement of commercial operation of Boiler 8 or after completion of the crop season, whichever

occurs first. For this facility, the sugarcane crop season is defined as October through April and the off-season is defined as May through September.

No later than ten (10) days after occurrence, the permittee shall provide written notification to the Compliance Authority of the permanent shutdown of Boiler 3 and of beginning commercial operation of Boiler 8. *{Permitting Note: Emissions decreases from the shutdown of Boiler 3 were used in the netting analysis to avoid PSD review of CO emissions for this project. The authorized shakedown period provides a reasonable period to start up the newly designed Boiler 8, test operations, and make necessary adjustments. A limited amount of concurrent operation is allowed because Boiler 8 is replacing Boiler 3 and must be fully tested during the crop season.}* [Design; Rule 62-212.400 (PSD), F.A.C.]

2. Construction of Boiler 8: The permittee is authorized to construct a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at design conditions of 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is ~~550,000~~ 633,000 pounds per hour based on a maximum 1-hour heat input rate of ~~1030~~ 1185 MMBtu per hour. Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse and/or wood chips. Low NOx burners will be used to fire distillate oil as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. Within 90 days of selecting the final design and vendor, the permittee shall submit the final primary design details of the proposed boiler. [Design]

3. Air Pollution Control Equipment: To comply with the standards of this permit, the permittee shall install the following air pollution control equipment.

   a. *~~Wet~~ Cyclone Collectors*: The permittee shall design, install, operate, and maintain a pre-control device prior to the electrostatic precipitator (ESP) to remove entrained sand and large particles in the flue gas. The purpose of the pre-control device is to prevent excessive equipment wear and overloading of the ESP. ~~The preliminary design is to locate t~~Two wet and one dry cyclone collectors are installed in parallel before the induced draft fan. ~~Upon written approval of the Department, equivalent equipment may be installed.~~

   b. *ESP*: The permittee shall design, install, operate, and maintain an electrostatic precipitator (ESP) to remove particulate matter from the flue gas exhaust and achieve the particulate matter standards specified in this permit. The ESP shall include an automated rapping system that can adjust rapping frequency and intensity to prevent re-entrainment of fly ash. The ESP shall be on line and functioning properly whenever bagasse and/or wood chips is fired.

   c. *SNCR*: The permittee shall design, install, operate, and maintain a urea-based selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide emissions in the flue gas exhaust and achieve the nitrogen oxides emissions standards specified in this permit. The system shall include automated control of urea injection for at least three injection zones to respond to varying load and flue gas conditions. Urea injection rates and zones will be determined based on parameters such as the current injection rate, furnace temperature profile, fuels, steam load, oxygen level, carbon monoxide level, and nitrogen oxide emissions.

   Within 90 days of selecting the final equipment designs and vendors, the permittee shall submit the final primary design details for the proposed pollution controls. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary fuel, wood chips as an alternate or supplemental fuel, and distillate oil as a restricted alternate fuel for startup and supplemental uses. Bagasse

is the fibrous material remaining after sugarcane is milled. Only new No. 2 (or superior) distillate oil containing no more than 0.05% sulfur by weight shall be fired. In addition, incidental amounts of on-specification used oil commingled with bagasse may be fired in Boiler 8 in accordance with the requirements in Appendix I of this permit. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

5. Boiler Capacities and Restrictions: The hours of operation are not restricted (8760 hours/year). The maximum continuous steam production capacity (24-hour average) is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour average). The total maximum heat input from the oil burners is 562 MMBtu per hour (4161 gallons/hour). Boiler 8 shall not exceed the following operational levels.
   a. ~~12,000,000~~ 13,800,000 pounds of steam per day (equivalent to ~~500,000~~ 575,000 pounds of steam per hour and ~~936~~ 1077 MMBtu per hour, 24-hour averages);
   b. $3.6135 \times 10^{+09}$ pounds of steam per consecutive 12 months (equivalent to 6,767,100 MMBtu per year);
   c. 99,864 gallons of distillate oil per day (equivalent to 13,488 MMBtu per day); and
   d. 6,073,600 gallons of distillate oil per consecutive 12 months (equivalent to 819,936 MMBtu per year).

   {Permitting Note: The short-term restrictions form the basis of the Air Quality Analysis. The restriction on annual steam production is a surrogate for heat input and allowed the project to avoid PSD applicability for carbon monoxide emissions. The annual oil firing restriction results in an annual capacity factor of 10% or less, which avoids specific requirements in NSPS Subpart Db.} [Design; Rules 62-4.070(3), 62-212.400 (PSD), 62-210.200(PTE), F.A.C.; NSPS Subpart Db]

6. Good Combustion and Operating Practices: The permittee shall follow the good combustion and operating practices identified in Appendix F of this permit. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: See Appendix E of this permit for a summary of the final BACT determinations.}

7. Standards Based on Stack Tests: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The mass emission rates (pounds per hour) are based on the maximum 24-hour heat input rate. Unless otherwise specified, compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.
   a. Ammonia Slip: As determined by EPA Conditional Test Method CTM-027, ammonia slip shall not exceed 20 ppmvd @ 7% oxygen. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]
   b. Carbon Monoxide (CO): To the extent practicable, short term emissions of carbon monoxide shall be controlled by implementing the good combustion and operating practices identified in Appendix F. [Rules 62-4.070(3), F.A.C.]
   c. Nitrogen Oxides (NOx): As determined by EPA Method 7E stack test, NOx emissions shall not exceed 0.14 lb/MMBtu and ~~131.0~~ 150.8 pounds per hour. *{Permitting Note: This standard is an "initial demonstration standard" intended to show the capabilities of the SNCR system as designed. After the initial compliance test, subsequent compliance shall be demonstrated with the long-term CEMS-based standard specified in Condition 8b.}* [Rule 62-212.400 (PSD), F.A.C.]
   d. Opacity: As determined by EPA Method 9 observations or COMS, the stack opacity shall not exceed 20% based on a 6-minute average. [Rule 62-212.400 (PSD), F.A.C.]
   e. Particulate Matter (PM/PM_{10}): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.025 lb/MMBtu and ~~23.4~~ 26.9 pounds per hour. [Rule 62-212.400 (PSD), F.A.C.; 40 CFR

63.7500]

f. Sulfur Dioxide (SO_2): As determined by EPA Method 6C stack test, SO_2 emissions shall not exceed 0.06 lb/MMBtu and ~~56.2~~ 64.6 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400 (PSD), F.A.C.]

g. Volatile Organic Compounds (VOC): As determined by EPA Methods 18 and 25A stack tests, VOC emissions shall not exceed 0.05 lb/MMBtu and ~~46.8~~ 53.9 pounds per hour measured as propane. For this permit, "VOC" emissions shall be defined as the total hydrocarbons (THC) measured by EPA Method 25A less the sum of the methane and ethane emissions as measured by EPA Method 18 on a concurrent sample. Alternatively, the permittee may elect to assume that all THC are regulated VOC emissions. [Rule 62-212.400 (PSD), F.A.C.]

h. Hydrogen Chloride (HCl): As determined by EPA Method 26 or 26A stack test, HCl emissions shall not exceed 0.02 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7500]

i. Mercury (Hg): As determined by the fuel analysis requirements specified in §63.7521 and Table 6 of Subpart DDDDD in 40 CFR 63, mercury emissions shall not exceed 0.000003 lb/MMBtu of heat input. For a summary of other applicable NESHAP requirements, see Appendix J of this permit. [40 CFR 63.7521]

8. Standards Based on CEMS: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels and under all load conditions.

   a. Carbon Monoxide (CO):

      1) As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 7% oxygen based on a 30-day rolling average. Carbon monoxide emission levels must be maintained below this work practice standard at all times except during periods of startup, shutdown, malfunction, and when the boiler or process heater is operating at less than 50% of rated capacity. For purposes of calculating data averages, data recorded during the following periods must not be used: periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when the boiler is operating at less than 50% of its rated capacity. All the data collected during all other periods must be used in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements. [40 CFR 63.7500(1), 63.7525(a)(6), 63.7540(a)(10) and Table 1 of Subpart DDDDD]

      2) As determined by CEMS data, CO emissions shall not exceed 1285 tons during any consecutive 12 months including periods of startup, shutdown, and malfunction. *{Permitting Note: Compliance with the annual mass emission standard ensures that the project is not subject to PSD preconstruction review for CO emissions.}* [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

   b. Nitrogen Oxides (NOx): As determined by CEMS data, NOx emissions shall not exceed 0.14 lb/MMBtu based on a 30-day rolling average. [Rule 62-212.400 (PSD), F.A.C.]

{Permitting Note: Appendix H of this permit specifies additional requirements regarding the initial shakedown period and initial demonstration of compliance for the CEMS-based standards.}

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

9. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with the following. If the permittee is

temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

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

11. <u>Excess Emissions - Allowed</u>: Unless otherwise specified by this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

12. <u>Excess Emissions – CO, NOx, and Opacity Requirements</u>: As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.

    a. *CO Emissions*: All valid CO CEMS data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the CO mass emission rate standard (tons per consecutive 12-months, rolling total). Compliance with the 30-day rolling CO standard shall be in accordance with the NESHAP requirements.

    b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, malfunction, and authorized periods of uncontrolled NOx monitoring may be excluded from the determination of compliance with the 30-day rolling emissions standard, provided:

        1) Best operational practices are used to minimize emissions;

        2) For startups and shutdowns, the SNCR system has not yet attained proper operating conditions and is not functional;

        3) For malfunctions, excluded data shall not exceed two hours in any 24-hour period (eight 15-minute CEMS blocks or quadrants of an hour). The permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

        4) For two hours each month, the permittee may operate the boiler without the SNCR system in order to collect uncontrolled NOx emissions data with the CEMS. For purposes of collecting uncontrolled NOx emissions data to adjust the SNCR system, excluded data shall not exceed two, 1-hour values during any calendar month. *{Permitting Note: Based on the final design specifications, uncontrolled NOx emissions are expected to be 0.30 lb/MMBtu. Uncontrolled NOx data collected during these periods will be used to adjust the SNCR system as necessary.}*

    c. *Opacity*: During startup and shutdown, the stack opacity shall not exceed 20% opacity based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity. This alternate opacity standard does not impose a separate annual testing requirement.

CO and NOx CEMS data excluded due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring shall be summarized and reported in the "Quarterly CO and NOx Emissions Report" required by this permit. *{Permitting Note: Allowances for nitrogen oxides are provided during specific* *periods in which the control device may not be fully operational because compliance is continuously demonstrated by CEMS data. Similarly, an alternate standard is identified for opacity during startup and shutdown because compliance is readily observable. As sulfur dioxide emissions are a function of the fuel sulfur, it is not expected that startups or shutdowns would cause excess emissions of this pollutant. It is possible that emissions of particulate matter and volatile organic compounds could exceed the permit standards in terms of "lb/MMBtu" during startups and shutdowns. However, the Department has good reason to believe that the mass emission rates of these pollutants (lb/hour) will not exceed the specified standards due to reduced loads and fuel firing rates. In any case, the specified test methods are generally applicable only during steady-state operation. Therefore, no alternate emissions standards are specified and compliance shall determined by the test methods and procedures specified in this permit. Compliance with the NESHAP Subpart DDDDD provisions for CO emissions shall be determined in accordance with the federal regulations. The Department's rules and permits cannot waive or supersede a federal requirement.}*

TESTING REQUIREMENTS

13. Boiler Performance Test: Within 180 days of first fire on bagasse, the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted when firing only bagasse and shall be at least three hours long. The boiler steam conditions and production rate shall be monitored and recorded during the test. The bagasse fuel firing rate (tons per hour) shall be calculated and recorded based on the steam parameters. A sample of the as-fired bagasse shall be analyzed for the heating value (Btu/lb) and moisture content (%). The actual heat input rate (MMBtu/hour) shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency of 62%. Results of the test shall be submitted to the Department within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. [Rule 62-4.070(3), F.A.C.]

14. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, Boiler 8 shall be tested to demonstrate initial compliance with the emission standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. The tests shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after the initial startup. Subsequent compliance stack tests for ammonia slip, PM, SO_2, VOC, and opacity shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate when firing only bagasse or bagasse with wood chips. CO CEMS data shall be reported for each run of the required tests for NOx and VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for NOx emissions may be used to demonstrate compliance with the initial stack test standards for this pollutant. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment.

Permit No. PSD-FL-333C modified the maximum heat input and steaming rates for Boiler 8. Pursuant to Rule 62-297.310(2), F.A.C., operation of Boiler 8 is limited to 110% of the latest test rate until a new test is conducted within 90% to 100% of the revised maximum 24-hour heat input rate that demonstrates compliance with the emissions standards for ammonia slip, NOx, PM, SO_2, VOC, and opacity. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting Note: All initial tests must be conducted at permitted capacity, ~~between~~ which is defined as 90% ~~and~~ to 100% of the maximum 24-hour heat input rate ~~permitted capacity~~; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.} [Rules 62-212.400 (PSD) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

15. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
CTM-027	Measurement of Ammonia Slip *{Note: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}*
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NOx Emissions (Instrumental)
9	Visual Determination of the Opacity
10	Measurement of Carbon Monoxide Emissions (Instrumental) *{Note: The CO test method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NOx, PM, and SO_2 Emission Rates
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

MONITORING REQUIREMENTS

16. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (° F), steam pressure (psig), and steam production rate (lb/hour). Records shall be maintained on site and made available upon request. [Design; Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

17. Fuel Monitoring: The permittee shall monitor each fuel in accordance with the following provisions. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

    a. *Distillate Oil:* In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain an oil flow meter with integrator. At the end of each day that oil is fired, the oil flow meter integrator shall be read and recorded in a written (or electronic) log. Initial compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority. During each federal fiscal year (October 1st to September 30th), the permittee shall take a sample from the storage tank and analyze for the fuel sulfur content. Sampling for the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90 (or more recent versions when available). For each delivery of distillate oil, the permittee shall maintain a permanent record of each certified fuel sulfur analysis provided by the fuel vendor. Records shall specify the date of delivery, the gallons delivered, the fuel sulfur content and test method.

    b. *Bagasse/Wood Chips*: Representative samples of bagasse and wood chips (if stored on site) shall be taken each calendar quarter and analyzed for the following: heating value (Btu/lb, as fired and dry); moisture content (percent by weight); sulfur content (percent by weight, dry); and ash content (percent by weight, dry). Records of the results of these tests shall be maintained on site and made available upon request.

18. CEMS: The permittee shall install, calibrate, operate and maintain continuous emission monitoring systems (CEMS) to measure and record concentrations of CO, NOx, and O_2 in the exhaust of Boiler 8 in a manner sufficient to demonstrate continuous compliance with the CEMS standards specified in this permit. The permittee shall notify the Compliance Authority within one working day of discovering emissions in excess of a CEMS standard subject to the specified averaging period. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial stack tests.

    a. *CO Monitors.* The CO monitor shall be installed, operated and maintained in accordance with the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.

    b. *NOx Monitors.* The NOx monitor shall be installed to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60. The monitor shall have a maximum span value of 250 ppmvd.

    c. *Diluent Monitors.* An oxygen monitor shall be installed at each CO and NOx monitor location to correct measured CO and NOx emissions to the required oxygen concentrations. The O_2 monitor shall meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 3A in Appendix A of 40 CFR 60. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

    d. *1-Hour Averages (NOx).* 1-hour block averages shall begin at the top of each hour. Each 1-hour average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the 1-hour average is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the 1-hour averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results shall be recorded in terms of "lb/MMBtu".

    e. *NESHAP Averaging (CO).* CO emissions shall be monitored and recorded pursuant to the applicable requirements in Subpart DDDDD of 40 CFR 63.

    f. *30-Day Averages (NOx).* The 30-day rolling average shall be determined by averaging all 1-hour averages for 30 successive boiler operating days. A boiler operating day begins and ends at midnight of each day and includes any day that fuel is combusted. Final results shall be recorded in terms of "lb/MMBtu".

    g. *Annual Averages (CO).* For each day (midnight to midnight), the CEMS shall record the total CO mass emissions rate (pounds per day). The 12-month rolling total shall be determined by summing the daily CO mass emission rates (pounds per day) for the 12-month period. The result shall be reported in terms of "tons per consecutive 12 months".

h. *Data Exclusion.* Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, and malfunctions. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 12 in this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

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

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; NESHAP Subpart DDDDD]

19. Alternate Opacity Monitoring Plan: Based on written approval from EPA Region 4, the permittee shall employ the following alternate sampling procedures in lieu of the requirement to install and operate a COMS. The procedures apply to the firing of distillate oil.

a. A certified EPA Method 9 observer shall perform a twelve-minute opacity test once per daylight shift during the period that the highest distillate oil firing rate occurs.

b. A certified EPA Method 9 observer shall perform a twelve-minute opacity test when the boiler achieves the normal operational load after a cold boiler startup with distillate oil.

c. Required observations shall be made in accordance with the provisions of EPA Method 9.

d. The observer shall maintain a log, which includes all of the information required by EPA Method 9 for each set of observations and the distillate oil firing rate (gph) during the observations.

e. Within 30 days after each calendar quarter, the permittee shall submit a copy of the observation log to the Compliance Authority for each observation performed during the quarter. The information shall also include a summary of the fuel usage and fuel analysis to verify that Boiler 8 has not exceeded the 10% annual capacity factor limit.

f. The permittee shall follow the boiler manufacturer's maintenance schedule and procedures to assure that serviceable components are well maintained.

g. If Boiler 8 exceeds the annual capacity factor limit of 10% for the combustion of distillate oil or is unable to regularly comply with the applicable opacity standard in §60.43b(f) when firing distillate oil, the permittee shall install and operate a COMS in accordance with the provisions of NSPS Subparts A and Db to demonstrate compliance with the opacity standards of the permit.

{Permitting Note: In a letter dated September 22, 2003, EPA Region 4 approved the above Alternate Opacity Monitoring Plan.} [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

20. ESP Monitoring Plan: To ensure proper functioning and effective performance of the electrostatic precipitator (ESP), the permittee shall submit a final ESP Monitoring Plan in accordance with the following requirements.

a. *Testing Program*: Within 90 days of the initial compliance stack tests, the permittee shall complete a testing program designed to establish the minimum total secondary power input to the ESP that indicates effective performance.

b. *Monitoring Provisions*: As part of the application for a Title V air operation permit, the permittee shall submit a final ESP Monitoring Plan that includes the following:

1) Based on the testing program, the plan shall specify the minimum total ESP secondary power input requirement (kW, 3-hour block average) that indicates effective performance.
2) The plan shall identify procedures to continuously monitor the ESP secondary voltage and secondary current, which will be used to calculate and record the total ESP secondary power input.
3) Continuous measurements shall be averaged into 15-minute blocks, which in turn will be averaged into 1-hour and 3-hour block averages beginning at the top of each hour, excluding monitoring malfunctions, associated repairs, and required QA/QC activities.
4) Excursions below the minimum level specified require investigation and corrective action.
5) The proposed plan shall incorporate appropriate QA/QC requirements to ensure valid data.

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

21. SNCR Urea Injection: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea injection rate for the SNCR system. The permittee shall document the general range of urea flow rates required to meet the NOx standard over the range of load conditions by comparing NOx emissions with urea flow rates. During NOx monitor downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

22. ~~Wet~~ Cyclones: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain the following equipment ~~on each wet cyclone~~: flow meter to monitor the water flow rate (gph) for each wet cyclone and a manometer (or equivalent) to monitor the pressure drop (inches of water) across each cyclone. At least once each 8-hour work shift, the flow rate and pressure drop shall be observed and recorded in a written log. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; 40 CFR 63.7500]

RECORDS AND REPORTS

23. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (MMBtu/hour), calculated bagasse firing rate (tons/hour), wood chip firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

24. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month of operation: hours of operation, distillate oil consumption, pounds of steam per month, and the updated 12-month rolling totals for each of these operating parameters. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled NOx emissions monitoring and CEMS systems monitor availability for the previous quarter. If CO or NOx CEMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See

Appendix G of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

FEDERAL REQUIREMENTS

26. NSPS Subpart Db: Boiler 8 is subject to the applicable New Source Performance Standards of Subpart Db in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix D of this permit summarizes these provisions.
27. NESHAP Subpart DDDDD: Boiler 8 is subject to the applicable National Emissions Standards for Hazardous Air Pollutants of Subpart DDDDD in 40 CFR 63 for "Industrial/Commercial/Institutional Boilers and Process Heaters". Appendix J of this permit summarizes these provisions.

B. Biomass Handling System (EU-027)

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

ID	Emission Unit Description
027	Biomass Handling System

EQUIPMENT

1. Modification of Existing System: The permittee is authorized to modify the existing biomass handling system to accommodate the additional biomass required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed biomass to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the biomass throughput of the handling system. Biomass means bagasse and/or wood chips. [Design; Rule 62-212.400 (PSD), F.A.C.]

2. ~~Air Pollution Control~~ Equipment: To minimize fugitive particulate matter, biomass conveyors shall be enclosed and ~~. Dust collectors~~ new landing zones shall be installed on conveyor transfer points. The conveyor system will now be completely enclosed except for the transfer points to/from the bagasse stockpile and the point associated with conveying bagasse from conveyor C9A to C9B in the drying mill. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. A cyclone separates the particles from the gas stream, which exhausts to ambient air. The fine particles are used as part of the cake material on the vacuum filters. ~~The preliminary design for the biomass conveyor dust collection system is based on the following specifications.~~

~~Dust Collector~~	~~Manufacturer~~	~~Model No.~~	~~Flow Rate (acfm)~~	~~Outlet (grains/afc)~~	~~Approximate Outlet Height (feet)~~
~~1~~	~~Prime Systems~~	~~BV-6X8-120~~	~~3550~~	~~0.02~~	~~57~~
~~2~~	~~Prime Systems~~	~~BV-8X8-120~~	~~3100~~	~~0.02~~	~~62~~
~~3~~	~~Prime Systems~~	~~BV-8X7-120~~	~~4725~~	~~0.02~~	~~61~~
~~4~~	~~Prime Systems~~	~~BV-6X8-120~~	~~3550~~	~~0.02~~	~~57~~
~~5~~	~~Prime Systems~~	~~BV-6X8-120~~	~~3550~~	~~0.02~~	~~57~~

~~*{Permitting Note: This system has previously been permitted and is under construction. The original plan called for the installation of six dust collectors. With the elimination of transfer belt conveyor No. 2, only the five dust collectors described above will be installed.}*~~ [Design; Application No. 0510003-037-AC]

EMISSIONS STANDARDS

3. Opacity: As determined by EPA Method 9, there shall be no visible emissions (≤ 5% opacity) from the bagacillo cyclone exhaust ~~dust collector outlets~~. [Rule 62-212.400 (PSD), F.A.C.]

TESTING REQUIREMENTS

4. Opacity Tests: ~~Within 180 days of completing construction of the biomass handling system and during the sugar mill season, an initial test shall be conducted in accordance with EPA Method 9 to demonstrate compliance with the opacity standard. Tests shall be conducted while the sugar mill and boilers are in normal operation. Each test shall be at least 30 minutes in duration. Subsequent tests shall be repeated for~~ In accordance with EPA Method 9, the bagacillo cyclone exhaust shall be tested during each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the opacity standard. [Rules 62-212.400 (PSD) and 62-297.310(7)(a)4, F.A.C.]

REPORTS

5. Test Report: Within 45 days of conducting an opacity test, the permittee shall submit a report to the Compliance Authority summarizing the results of the test. [Rule 62-297.310(8), F.A.C.]

Contents

Appendix A. Citation Formats
Appendix B. General Conditions
Appendix C. Common Requirements
Appendix D. NSPS Provisions
Appendix E. Summary of Final BACT Determinations
Appendix F. Good Combustion and Operating Practices
Appendix G. Quarterly CO and NOx Emissions Report
Appendix H. Shakedown Period
Appendix I. Incidental Amounts of On-Specification Used Oil with Bagasse and or Wood Chips
Appendix J. NESHAP Provisions

SECTION 4. APPENDIX A

Citation Formats

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

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

Where: "AC" identifies the permit as an Air Construction Permit

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

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

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

"2222" represents the specific facility ID number

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

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

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

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

PSD Permit Numbers

Example: Permit No. PSD-FL-317

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

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

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7 or §60.7]

Means: Title 40, Part 60, Section 7

General Conditions

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

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

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

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

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Common Requirements

Unless otherwise specified by permit, the following conditions apply to all emissions units and activities at this facility.

Definitions

1. Excess Emissions: Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot-blowing, load changing or malfunction. [Rule 62-210.200(106), F.A.C.]
2. Shutdown: The cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]
3. Startup: The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(246), F.A.C.]
4. Malfunction: Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

Emissions and Controls

5. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
6. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
7. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
8. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
9. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
10. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
11. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]
12. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as confining, containing, covering, and/or applying water to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input: *{Permitting Note: Rule 62-296.405(2), F.A.C. specifies that that new units are subject to the applicable standards in NSPS Subparts D or Da for opacity, particulate matter, sulfur dioxide, and nitrogen oxides. However, NSPS Subpart D is not applicable because the project is also subject to the more recent NSPS Subpart Db, which states that such units are not also subject to NSPS Subpart D. See §60.40b(j) in Appendix D. NSPS Subpart Da is not applicable to this project because the boiler is not an electric utility steam generating unit.}*

15. Carbonaceous Fuel Burning Equipment: Rule 62-296.410(2)(b), F.A.C. establishes the following standards for new emissions units with burners of a capacity equal to or greater than 30 MMBtu per hour total heat input.

    a. *Visible Emissions*: 30 percent opacity except that 40 percent opacity is permissible for not more than two minutes in any one hour.

    b. *Particulate Matter*: 0.2 pounds per MMBtu of heat input of carbonaceous fuel plus 0.1 pounds per million Btu heat input of fossil fuel.

{Permitting Note: The BACT standards specified in the permit are much more stringent than the standards specified in Rules 62-296.405(2) and 62-296.410(2)(b), F.A.C.}

TESTING REQUIREMENTS

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

17. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

18. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

19. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

20. 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.]

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

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

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

24. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

    1. The type, location, and designation of the emissions unit tested.
    2. The facility at which the emissions unit is located.
    3. The owner or operator of the emissions unit.
    4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
    5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
    6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
    7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
    8. The date, starting time and duration of each sampling run.
    9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
    10. The number of points sampled and configuration and location of the sampling plane.
    11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
    12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

25. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. Information recorded and stored as an electronic file shall be made available within at least three days of a request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
26. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370, F.A.C.]

NSPS Provisions

The following emissions unit is subject to applicable New Source Performance Standards (NSPS) in 40 CFR 60 and adopted by reference in Rule 62-204.800(8), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of ~~500,000~~ 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 60, Subpart A - NSPS General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units

Boiler 8 shall comply with the applicable requirements of Subpart Db in 40 CFR 60, which are adopted by reference in Rule 62-204.800(8), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and related requirements are shown in italics immediately following the pertinent section. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.}

§60.40b Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu/hour.

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(g) In delegating implementation and enforcement authority to a State under Section 111(c) of the Act, the following authorities shall be retained by the Administrator and not transferred to a State: (1) §60.44b(f); (2) §60.44b(g); and (3) §60.49b(a)(4).

{Permitting Note: NSPS Subpart Db applies because the maximum heat input from oil firing is 562 MMBtu per hour.}

§60.41b Definitions

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydro-desulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference - see §60.17).

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, re-circulated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

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

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 0.5 lb/million BTU heat input.

<u>§60.42b Standard for Sulfur Dioxide</u>

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil (0.5% sulfur by weight). The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (2) maintaining fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO2 emission standard for the boiler flue gas or a percent reduction requirement because the permit restricts distillate oil to no more than 0.05% sulfur by weight. The permit includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

<u>§60.43b Standard for Particulate Matter</u>

(b) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 0.10 lb/million Btu heat input. *{Not applicable; see "Permitting Note" at end of section.}*

(c) On and after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, 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.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

{Permitting Note: NSPS Subpart Db does not impose a particulate matter emission standard for the boiler flue gas for oil firing because no equipment will be necessary to reduce SO_2 emissions. The permit limits stack opacity to this level or less.}

<u>§60.44b Standard for Nitrogen Oxides</u>

(a) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, 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 coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

(1) Natural gas and distillate oil:

(i) Low heat release rate: 0.10 lb/million BTU of heat input (expressed as NO_2)

{Not applicable; see "Permitting Note" at end of section.}

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixture of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction. *{Not applicable; see "Permitting Note" at end of section.}*

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis. *{Not applicable; see "Permitting Note" at end of section.}*

{Permitting Note: Boiler 8 is a low heat release rate boiler (20,497 Btu/ft^3 on bagasse and 11,184 Btu/ft^3 on distillate oil) and will fire distillate oil during startup or as a supplemental fuel. As described in paragraph (c) above, NSPS Subpart Db does not impose a NOx standard for the boiler flue gas when firing a combination of bagasse and distillate oil because the permit limits distillate oil firing to an annual capacity factor of no more than 10%.}

<u>§60.45b Compliance and Performance Test Methods and Procedures for Sulfur Dioxide</u>

(j) The owner or operator of an affected facility that combusts very low sulfur oil (≤ 0.5% sulfur by weight) is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: NSPS Subpart Db does not impose a specific SO_2 emissions limit for the boiler flue gas because the boiler will combust only distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.46b Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(a) The particulate matter emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under §60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under Sec. 60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(d) To determine compliance with the particulate matter and emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8 using the following procedures and reference methods:

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160° C (320° F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets

(iii) Method 5B is to be used only after wet FGD systems.</SUP>

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160° C (320° F).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Method 9 is used for determining the opacity of stack emissions.

{Permitting Note: NSPS Subpart Db imposes only a particulate matter and opacity standard because the boiler is restricted to an annual capacity factor of no more than 10% for firing oil. The permit requires testing in accordance with EPA Method 9.}

§60.47b Emission Monitoring for Sulfur Dioxide

(f) The owner or operator of an affected facility that combusts very low sulfur oil (≤ 0.5% sulfur by weight) is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

{Permitting Note: The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur content.}

§60.48b Emissions Monitoring for Particulate Matter and Nitrogen Oxides

(a) The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. *{Permitting Note: In lieu of the continuous opacity monitoring*

requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil.}

§60.49b Reporting and Recordkeeping Requirements

(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) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i), and

(3) 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 sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §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 using the applicable performance specifications in Appendix B. *{Not applicable; see "Permitting Note" at end of section.}*

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

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

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

{Permitting Note: In lieu of the continuous opacity monitoring requirements, EPA Region 4 approved the alternate sampling procedure specified in the permit on September 22, 2003. The procedure includes additional EPA Method 9 observations when firing distillate oil. The permit limits distillate oil to no more than 0.05% sulfur by weight and includes fuel sampling, analysis, and record keeping requirements to monitor the fuel sulfur. The permit also restricts the firing of distillate oil to an annual capacity factor of no more than 10%.}

Summary of Final BACT Determinations

Project Description

U.S. Sugar Corporation proposes to install a balanced draft, membrane wall, spreader stoker boiler to generate superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The design thermal efficiency is 62% and the maximum 1-hour steam production rate is ~~550,000~~ 633,000 pounds per hour based on a maximum 1-hour heat input rate of ~~1030~~ 1185 MMBtu per hour. The maximum continuous steam production is ~~500,000~~ 575,000 pounds per hour based on a maximum heat input rate of ~~936~~ 1077 MMBtu per hour (24-hour averages). Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used fire the primary fuel of bagasse (and wood chips as an alternate or supplemental fuel). Distillate oil will be fired as a restricted alternate fuel for startup and supplemental uses. Bottom ash will be removed to ash ponds by a submerged conveyor. The project will also modify the existing bagasse handling system to accommodate the additional bagasse required for Boiler 8. These changes include: expanding conveyor belt C4; adding a new conveyor belt to feed bagasse to Boiler 8; eliminating transfer belt conveyor No. 2 and increasing the bagasse throughput of the bagasse handling system.

Air Pollution Control Equipment

Boiler 8: Particulate matter will be controlled by ~~wet~~ cyclone collectors followed by an electrostatic precipitator (ESP) with approximately a 99% reduction. Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction (SNCR) system (~ 50% reduction). Other NOx reduction techniques include low NOx burners for distillate oil, overfire air, and low nitrogen fuels. The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide, volatile organic compounds, and organic hazardous air pollutants. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide.

Biomass Handling System: To minimize fugitive particulate matter from the biomass handling system, biomass conveyors will be enclosed and ~~dust collectors~~ new landing zones will be installed on the conveyor transfer points. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. A cyclone separates the particles from the gas stream, which exhaust to ambient air. The fine particles are used as part of the cake material on the vacuum filters.

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards for Boiler 8 that represent the Best Available Control Technology (BACT) for emissions nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Pollutant	Standards - Stack Test [a]	Standards – CEMS [b]
EU-027: Biomass Handling System		
Opacity [c]	There shall be no visible emissions (≤ 5% opacity) from the ~~dust collector~~ bagacillo cyclone exhaust outlets.	
EU-028: Boiler 8		
CO [d]	Good Combustion Practices	1285 tons per consecutive 12 month rolling total (Avoids PSD Review)
NOx	0.14 lb/MMBtu {Initial demonstration standard; subsequent compliance based on CEMS.}	0.14 lb/MMBtu, 30-day rolling average
PM	0.025 lb/MMBtu [e]	Not Applicable
SO_2 (Surrogate for SAM)	0.06 lb/MMBtu	Not Applicable
	Fuel Specification: Distillate oil shall be new No. 2 oil containing no more than 0.05% sulfur by weight.	
VOC	0.05 lb/MMBtu	Not Applicable
Opacity [c]	During normal operation, stack opacity shall not exceed 20% based on a 6-minute block average. During startup or shutdown, stack opacity shall not exceed 20% based on a 6-minute block average except for one 6-minute block per hour that shall not exceed 27%.	

a. These standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The permit also establishes maximum hourly mass emission rates based on operation at permitted capacity. Compliance with the standards based on stack tests shall be determined by the following EPA stack test methods: NOx (EPA Method 7E); PM (EPA Method 5); SO_2 (EPA Method 6C); VOC (EPA Methods 18 and 25A, as propane); and opacity (EPA Method 9). Compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

b. These standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels and under all load conditions. Compliance with the CO and NOx CEMS-based standards shall be demonstrated by data collected from the required continuous emissions monitoring systems (CEMS) required for these pollutants. The permit allows specific NOx CEMS data to be excluded from the compliance determination (30-day rolling average) when the SNCR system is not functioning due to startup, shutdown, malfunction, or authorized periods of uncontrolled NOx monitoring. The CO monitor shall meet the applicable requirements in Subpart DDDDD of 40 CFR 63. The NOx monitor shall meet the requirements of Performance Specification 2 in Appendix B of 40 CFR 60. An oxygen monitor shall be installed and meet the requirements of Performance Specification 3 in Appendix B of 40 CFR 60 to correct the CO and NOx emission rates.

c. NSPS Subpart Db requires a Continuous Opacity Monitoring System (COMS) for new industrial boilers firing "coal, oil, wood or mixtures of these fuels", which applies at all times except startup, shutdown, or malfunction. Therefore, the COMS is required by NSPS Subpart Db when Boiler 8 fires distillate oil alone or in combination with bagasse and/or wood chips. In lieu of the COMS requirements for Boiler 8, EPA Region 4 approved (September 22, 2003) an alternate sampling procedure that includes additional EPA Method 9 observations when firing distillate oil. In addition, the draft permit requires monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP.

d. Based on a netting analysis that included emissions decreases resulting from the shut down of existing Boiler 3, the project did not require PSD preconstruction review for carbon monoxide (CO) emissions. The permit requires the permanent shutdown of Boiler 3 prior to the commercial operation of new Boiler 8.

e. The original PSD permit considered the proposed particulate matter standard for new, large solid fuel fired boilers specified in NESHAP Subpart DDDDD (0.026 lb/MMBtu). The final version of this regulation revised the particulate matter standard to 0.025 lb/MMBtu. For simplicity and clarity, the applicant specifically requested that the BACT standard be reduced to be equivalent to the NESHAP standard. Permit No. PSD-FL-333B revised the standard accordingly.

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original project as well as subsequent revisions.

Good Combustion and Operating Practices

The determination of Best Available Control Technology (BACT) for emissions of carbon monoxide and volatile organic compounds (VOC) from Boiler 8 relied on an efficient boiler design and good combustion and operating practices. To the extent practicable, the permittee shall employ the following procedures to minimize emissions and promote good combustion and pollution control.

Startup and Shutdown

1. Training: All operators and supervisors shall be properly trained to operate and maintain Boiler 8 as well as the pollution control and monitoring equipment in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions during startups, shutdowns, and malfunctions.

2. Boiler Startup: During a normal startup, Boiler 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100° F to 120° F per hour, it will take approximately ~~4 to 5~~ 6 to 7 hours to reach the desired superheater steam temperature of ~~500~~ 650° F. Once this temperature is achieved, the boiler is placed into service (i.e., steam sent to steam header) and distillate oil is fired for another 1 to 2 hours to stabilize temperatures. ~~Once this temperature is reached~~ Then, bagasse (and/or wood chips) will be fed until a fire is established across the entire grate. The full steaming rate can be reached about ~~30 to 60 minutes~~ 1 to 3 after first feeding bagasse (and/or wood chips). A boiler startup may take just a few hours up to a maximum of 12 hours depending on the duration of shutdown, boiler temperatures, control equipment temperatures, and the biomass being fired.

3. PM Controls: The wet cyclone collectors will be activated before firing any fuel. Prior to activation, the ESP will be purged with ambient air for about 30 to 60 minutes. Distillate oil may be fired during startup prior to energizing the electrostatic precipitator (ESP). The ESP will be on line and functioning properly before any bagasse and/or wood chips are fired. The ESP will remain on line until the bagasse feed has stopped and combustion on the grate is substantially complete.

4. NOx Controls: When the SNCR manufacturer's minimum operating temperature requirement is met, the SNCR system will be activated for NOx control. For a cold startup, this temperature is generally reached within 4 - 5 hours of initial distillate oil firing. During normal operation, the SCNR control system will automatically adjust the urea injection rate and zones to meet the specified NOx standard based on the current urea injection rate, boiler load, furnace temperature, and NOx emissions. During shutdown, the SNCR system shall remain operational until the operating temperature drops below the minimum requirement.

5. Good Combustion Practices: To the extent practicable, the permittee shall maintain the following flue gas levels as indicators of good combustion:

   a. *Oxygen*: The permittee shall install, maintain, and operate a flue gas oxygen monitor on Boiler 8. When firing bagasse during normal operation, the flue gas oxygen content is expected to range from 3% and 4%. High fuel moisture, high ash content, and low load conditions may result in higher flue gas oxygen contents (5% - 6%). When firing only distillate oil, the flue gas exhaust oxygen content is expected to range from 8% and 9% due to tramp air required for cooling of the stoker, pneumatic distributors, and overfire air nozzles. Operators shall ensure that the flue gas oxygen content is sufficient for good combustion.

   b. *Carbon Monoxide (CO)*: Carbon monoxide is an indicator of incomplete fuel combustion. In addition to insufficient oxygen, high fuel moisture, high ash content and low load conditions may result in elevated levels of carbon monoxide. When firing bagasse and/or wood chips during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen. The operator shall use the measured CO emissions at the stack as an indicator of the combustion efficiency and adjust boiler operating conditions as necessary. *{Permitting Note: The stack exhaust is expected to be 1% - 2% (oxygen content) higher than the boiler exhaust due to infiltration from the entire system.}*

   When firing bagasse and/or wood chips, many factors may affect efficient combustion. The above levels represent adherence to good combustion practices under normal operating conditions. Operation outside these levels is not a violation in and of itself. Repeated operation beyond these levels without taking corrective actions to regain good combustion could be considered "circumvention" in accordance with Rule 62-210.650, F.A.C.

6. Boiler Shutdown: To initiate shutdown, the bagasse and/or wood chips fuel feed is terminated. The SNCR systems shall remain functional until operating conditions fall outside of the manufacturer's recommendations. The ~~wet~~ cyclone collectors and ESP shall continue to operate until solid fuel combustion on the fuel grate is substantially complete.

Quarterly CO and NOx Emissions Report

Current Title V Permit No. ____________________

Facility Name	**ARMS ID No.**	**ARMS EU ID No.**
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	0510003	028

Emissions Unit Description

Boiler 8 is a spreader stoker boiler with maximum continuous steam rate of 500,000 lb/hour. Control equipment includes:

- CO/VOC – Efficient combustion design and good operating practices
- NOx – Low NOx oil burners and selective non-catalytic reduction (SNCR) system
- PM/PM10 – Wet cyclone collectors and electrostatic precipitators

Primary Fuel	**Auxiliary Fuels**
Bagasse – Fibrous plant material remaining after sugarcane is milled	Distillate oil (≤ 0.05% sulfur by weight) Wood chips: alternate or supplemental fuel

Year	**Calendar Quarter of Operation Covered** ***(Check one.)***	**Unit Operation in Calendar Quarter**
	___ 1 ___ 2 ___ 3 ___ 4	________ hours

Continuous Emissions Monitoring System (CEMS) Information

Pollutant Monitored: _____ CO _____ NOx Manufacturer: ____________________

Date of last certification or audit: ____________________ Model No. ____________________

Emission Data Summary

1. Standard: ____________________
2. Hours of excess emissions in reporting period due to:
   a. Startup/shutdown .... _____
   b. Control equipment problems .... _____
   c. Process problems .... _____
   d. Other known causes .... _____
   e. Unknown causes .... _____
2. Total hours of excess emissions .... _____
3. (Total hours of excess emissions) / (Total hours of source operating time) x (100%) .... _____

Note: Report "excess emissions" for any emission averages that are in excess of a permitted emissions standard and averaging period.

CEMS Performance Summary

1. Hours of CEMS downtime in reporting period due to:
   a. Monitor equipment malfunctions .... _____
   b. Non-monitor equipment malfunctions .... _____
   c. Quality assurance calibration .... _____
   d. Other known causes .... _____
   e. Unknown causes .... _____
2. Total hours of CEMS downtime .... _____
3. (Total hours of CEMS downtime) / (Total hours of source operating time) x (100%) .... _____

If monitor availability is not at least 95%, provide a report identifying the problems and a plan of corrective actions that will be taken to achieve 95% availability

Emissions Data Exclusion

1. Report the number of 1-hour emissions averages excluded the reporting period due to:
   a. Startups: _____ c. Malfunctions: _____ e. Total _____
   b. Shutdowns: _____ d. Uncontrolled NOx Monitoring: _____
2. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
3. On a separate page, describe any changes to the CEMS, process equipment, or control equipment during last quarter.

Emission Rates

On a separate page, report the actual emissions for: each rolling 12-month total (tons) of CO emissions for each month in the quarter, and each 30-day rolling NOx average (ppmvd @ 7% oxygen) for each compliance period in the quarter.

Certification

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

Print Name / Title	**Signature / Date**

Shakedown Period

Boiler 8 will be a new type of spreader-stoker specifically designed for the efficient combustion of bagasse and/or wood chips as an alternate or supplemental fuel. Bagasse is the fibrous byproduct remaining from sugarcane after the milling process. The sugarcane milling season runs from October through April. The proposed startup date for the new boiler is January of 2005, which is approximately halfway through the sugarcane milling season. It is expected that a short, initial shakedown period will be necessary for the boiler prior to shakedown of the SNCR system. Although the facility also includes a refinery that operates during the milling off-season, Boiler 8 is not expected to operate much during the off season unless refinery steam demands are high enough to take advantage of large steam production rate from this unit. For these reasons, the Department authorizes the following shakedown period in accordance with the specific conditions, which are in addition to those specified in Section 3 of the permit.

1. Shakedown: Shakedown is limited to the first 360 calendar days after first fire in the boiler and shall not exceed 180 operational days after first fire in the boiler. An "operational day" is any day that Boiler 8 fires any fuel. During shakedown, Boiler 8 shall not operate more than 60 days during the off-season. For this plant, the sugarcane crop season is defined as October through April and the off-season is defined as May through September. Shakedown is complete once commercial operation is established. In addition, shakedown shall end no later than 60 days after Boiler 8 achieves a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average.

2. SNCR System: During the shakedown period, the permittee is authorized to operate the boiler without the SNCR system for purposes of commissioning the boiler and collecting uncontrolled NOx emissions data, provided:

   a. During the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed a total of 240 hours;

   b. After the first 90 operational days of shakedown, operation without the SNCR system functioning shall not exceed 2 hours each day; and

   c. Notwithstanding the above periods, the operator shall fully utilize the SNCR system to the extent practicable and according to the manufacturer's recommended procedures.

3. CO and NOx CEMS: The CO and NOx CEMS shall be installed and certified within the first 45 operational days of shakedown. CEMS data collected on the first full day following completion of the shakedown period shall be used to begin demonstrating compliance with the CEMS-based emissions standards of the permit.

4. Initial Stack Tests: All initial stack tests required by this permit shall be conducted during the defined shakedown period, but no later than 60 days after achieving the maximum production rate, which is defined as a maximum continuous rating of 450,000 lb/hour of steam based on a 24-hour average. The permittee shall provide written notification to the Permitting and Compliance Authorities within 10 days of achieving this maximum production rate.

{Permitting Note: After demonstrating compliance and commencing commercial operation, the conditions of Appendix H will become obsolete and need not be included in the Title V air operation permit. The above requirements do not supersede any federal requirements regarding shakedowns for purposes of complying with NSPS or NESHAP regulations. Boiler 8 has a maximum heat input rate greater than 100 MMBtu/hour and is permitted to fire bagasse as the primary fuel, wood chips as an alternate or supplemental fuel, and distillate oil as a startup and supplemental fuel. As such, it is an "affected facility" as defined in NSPS Subpart Db of 40 CFR 60. This NSPS regulates emissions of sulfur dioxide, particulate matter, opacity, and nitrogen oxides for the firing of coal, oil, or natural gas (or mixtures of these fuels with other fuels). However, the NSPS standards for particulate matter and sulfur dioxide are not applicable because the new boiler does not employ add-on controls to reduce sulfur dioxide emissions. Instead, sulfur dioxide emissions are limited by the firing of very low sulfur distillate oil and bagasse and/or wood chips. In turn, the nitrogen oxide emission standard does not apply because the annual capacity factor for the very low sulfur distillate oil is less than 10% as conditioned by the permit. Only opacity is regulated by NSPS Subpart Db for this new boiler when firing distillate oil. Boiler 8 is also subject to the applicable requirements of NESHAP Subpart DDDDD in 40 CFR 63.}

Incidental Amounts of On-Specification Used Oil with Bagasse and/or Wood Chips

Description

The facility generates small amounts of on-specification used oil consisting mostly of hydraulic fluids and lubrication oils (<< than 10,000 gallons per year). Leaks or spills of these fluids are removed from the work areas by absorbing with bagasse and/or wood chips and then adding to the common biomass conveyor for firing in any of the boilers. The amount of oil is incidental and would not affect emissions.

Requirements

1. Firing: The permittee may fire incidental amounts of bagasse/on-specification oil with other authorized fuels in any of the mill boilers. To the extent practicable, the bagasse/on-specification oil shall be commingled with bagasse and/or wood chips in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C.]

2. Used Oil Specifications: Incidental amounts of used oil to be fired in the boilers shall be on-specification used oil generated on site at this facility. The permittee shall maintain records sufficient to document that the used oil meets the following requirements:

   a. The used oil shall not contain PCBs.

   b. The used oil shall meet the following EPA specifications for "on-specification used oil" in Subpart B of 40 CFR 279:

      Arsenic shall not exceed 5.0 ppm;
      Cadmium shall not exceed 2.0 ppm;
      Chromium shall not exceed 10.0 ppm;
      Lead shall not exceed 100.0 ppm;
      Total halogens shall not exceed 1000.0 ppm; and
      The flash point shall not be less than 100 degrees F.

   Used oil that does not meet the above requirements shall not be burned at this facility. [Rule 62-4.070, F.A.C.; Subpart B, 40 CFR 279]

3. Records: The permittee shall keep records sufficient to document compliance with the above requirements. The records shall be made available when requested by the Compliance Authority. [Rule 62-4.070, F.A.C.]

NESHAP Provisions

The following emissions unit is subject to applicable National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63 and adopted by reference in Rule 62-204.800(11), F.A.C.

EU No.	Description
028	Boiler 8 – Spreader stoker boiler rated at a maximum continuous steam production rate of ~~500,000~~ 575,000 pounds per hour (24-hour average). Fuels include bagasse, wood chips, and/or distillate oil. The maximum heat input from oil firing is 562 MMBtu per hour, but the annual capacity factor is limited by permit to less than 10%.

40 CFR 63, Subpart A - NESHAP General Provisions

Boiler 8 shall comply with the applicable General Provisions of Subpart A in the National Emission Standards for Hazardous Air Pollutants including: §63.1 Applicability; §63.2 Definitions; §63.3 Units and abbreviations; §63.4 Prohibited activities and circumvention; §63.5 Preconstruction review and notification requirements; §63.6 Compliance with standards and maintenance requirements; §63.7 Performance testing requirements; §63.8 Monitoring requirements; §63.9 Notification requirements; §63.10 Recordkeeping and reporting requirements; §63.11 Control device requirements;§63.12 State authority and delegations; §63.13 Addresses of State air pollution control agencies and EPA Regional Offices; §63.14 Incorporations by reference; §63.15 Availability of information and confidentiality; §63.16 Performance Track Provisions. The General Provisions are not included in this permit, but can be obtained from the Department upon request.

40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters

Boiler 8 shall comply with all applicable requirements of Subpart DDDDD in 40 CFR 63, which are adopted by reference in Rule 62-204.800(11), F.A.C. For purposes of this regulation, Boiler 8 is classified as a new, large (> 100 MMBtu/hour), solid fuel (bagasse) industrial boiler. As such, the unit is subject to the following primary requirements:

Pollutant	Emission Limits	Requirements
Particulate Matter (PM)	0.025 lb/MMBtu of heat input	• Surrogate limit for total selected metals (TSM) • Compliance by EPA Method 5 stack test • Compliance test establishes allowable "operating limits" (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • Continuous compliance by continuous monitoring (3-hour averages) for the wet cyclone (pressure drop and flow rate) and the ESP (total power input) • A COMS is not required due to the wet cyclone scrubber
Hydrogen Chloride (HCl)	0.02 lb/MMBtu of heat input	• Compliance by EPA Method 26 or 26A stack test • Monitoring is same as for particulate matter • Scrubber pH monitoring not required (EPA Region 4 letter dated September 4, 2005)
Mercury (Hg)	0.000003 lb/MMBtu of heat input	• Compliance by fuel sampling and analysis methods
Carbon Monoxide (CO)	400 ppmvd @ 7% oxygen (30-day rolling average)	• Surrogate limit for organic HAPs • Compliance by data collected from CO CEMS • CEMS shall be installed, operated and maintained in accordance with the provisions of §63.7525

The following pages contain a table of contents for NESHAP Subpart DDDDD as well as the summary tables from this Subpart that are applicable to Boiler 8.

What This Subpart Covers

63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards

63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

General Compliance Requirements

63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the HCl and TSM standards?

Testing, Fuel Analyses, and Initial Compliance Requirements

63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

Continuous Compliance Requirements

63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

Notifications, Reports, and Records

63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

Other Requirements and Information

63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63

Table 1. Emission Limits and Work Practice Standards
Table 2. Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits
Table 3. Operating Limits for Boilers and Process Heaters with Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4. Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Emission Limits
Table 5. Performance Testing Requirements
Table 6. Fuel Analysis Requirements
Table 7. Establishing Operating Limits
Table 8. Demonstrating Continuous Compliance
Table 9. Reporting Requirements
Table 10. Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD

Appendix A. Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B. Applicability of General Provisions to Subpart DDDDD

TABLE 1. Emission Limits and Work Practice Standards

As stated in §63.7500, Boiler 8 shall comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
1. New Large Solid Fuel	a. Particulate Matter (for Total Selected Metals)	0.025 lb per MMBtu of heat input
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input
	c. Mercury	0.000003 lb per MMBtu of heat input
	d. Carbon Monoxide	400 ppmvd corrected to 7 percent oxygen (30-day rolling average) based on data collected from a CO CEMS

The following provisions cover periods of startup, shutdown, and malfunction.

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §63.7 and §63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §63.7525(a) and §63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §63.6(e) and §63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance

with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

TABLE 2. Operating Limits for Boilers with Particulate Matter Emission Limits

As stated in §63.7500, Boiler 8 shall comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet Scrubber Control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
3. Electrostatic Precipitator Control	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

TABLE 4. Operating Limits for Boilers with Hydrogen Chloride Limits

As stated in §63.7500, Boiler 8 shall comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet Scrubber Control	Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 5. Performance Testing Requirements (Particulate Matter and Hydrogen Chloride)

As stated in §63.7520, Boiler 8 shall comply with the following performance test requirements:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure particulate matter emissions concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen Chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).

To conduct a performance test for the following pollutant	You must	Using
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the HCl concentration.	Method 26 or 26A in appendix A to part 60.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

TABLE 6. Fuel Analysis Requirements (Mercury)

As stated in §63.7521, Boiler 8 shall comply with the following fuel analysis testing requirements:

To conduct a fuel analysis for the following pollutant	You must	Using
1. Mercury	a. Collect fuel samples (The permittee notes that samples will be taken from a moving belt.)	Procedure in §63.7521(c) or ASTM D2234-001 (for coal)(IBR, see §63.14(b)) or ASTM D6323-98 (2003)(for biomass)(IBR, see §63.14(b)) or equivalent
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent
	c. Prepare composite fuel samples	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) (IBR, see §63.14(b)) or ASTM D5198-92 (2003) (for biomass)(IBR, see §63.14(b)) or equivalent
	d. Determine heat content of the fuel type	ASTM D5865-03a (for coal)(IBR, see §63.14(b)) or ASTM E711-87 (1996) (for biomass)(IBR, see §63.14(b)) or equivalent
	e. Determine moisture content of the fuel type	ASTM D3173-02 (IBR, see §63.14(b)) or ASTM E871-82 (1998)(IBR, see §63.14(b)) or equivalent
	f. Measure mercury concentration in fuel sample.	ASTM D3684-01 (for coal)(IBR, see §63.14(b)) or SW-846-7471A (for solid samples) or SW-846-7470A (for liquid samples)
	g. Convert concentrations into units of "lb/MMBtu" of heat content.	

TABLE 7. Establishing Operating Limits

As stated in §63.7520, Boiler 8 shall comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
1. Particulate Matter	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1)Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a)You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests (b)Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control)	i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c)	(1)Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test	(a)You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests (b)Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
				test run

TABLE 8. Demonstrating Continuous Compliance

As stated in §63.7540, Boiler 8 shall show continuous compliance with the emission limitations as follows:

If you must meet the following operating limits or work practice standards	You must demonstrate continuous compliance by
3. Wet Scrubber Pressure Drop and Liquid Flow Rate *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).
6. Precipitator Secondary Current and Voltage or Total Power Input *(For Particulate Matter and Hydrogen Chloride)*	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §63.7525 and §63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §63.7530(c)
7. Fuel Pollutant Content *(For Mercury)*	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to §63.7540(a).

Compliance with the above operating limits and work practice standards demonstrate continuous compliance with the emission limits for PM, HCl, and Hg. A COMS for opacity is not required due to the wet cyclone scrubber. The CO emission limit (400 ppmvd @ 7% oxygen based on a 30-day rolling average) is set as a work practice standard for controlling emissions of organic HAPs. Continuous compliance with the CO limit is demonstrated by data collected with the required CEMS. Although Boiler 8 is controlled by a wet cyclone scrubber, performance tests conducted without the scrubber in operation show compliance with the HCl emission limit. Therefore, pH monitoring is not required. See EPA Region 4 letter dated September 4, 2005.

TABLE 9. Reporting Requirements

As stated in §63.7550, Boiler 8 shall comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance Report	a. Information required in §63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	Semiannually according to the requirements in §63.7550(b).

You must submit a(n)	The report must contain	You must submit the report
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in §63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

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October 20, 2006

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RECEIVED

OCT 23 2006

BUREAU OF AIR REGULATION

Attention: Mr. Jeff Koerner, BAR, Air Permitting North

RE: UNITED STATES SUGAR CORPORATION, CLEWISTON MILL BOILER NO. 8 STEAM RATE INCREASE PERMIT REVISION APPLICATION PERMIT NO. 0510003-037-AC REQUEST FOR ADDITIONAL INFORMATION

Dear Mr. Jeff Koerner:

United States Sugar Corporation (U.S. Sugar) and Golder Associates Inc. have received the Florida Department of Environmental Protection's (FDEP) email requests for additional information (RAI) dated June 23 and June 30, 2006. We have reviewed the RAI and developed responses to each of the FDEP's comments. The responses are provided below.

June 23, 2006 Email

Comment 1. Steam Rate Increase: Please submit some operational data indicating the steam rate of Boiler 8 as constructed.

Response: Operational data, which is based on U.S. Sugar's continuous emissions monitoring system (CEMS), was obtained for Boiler No. 8 for operations during the crop season (November 1, 2005 through April 10, 2006). As presented in Table 1, the maximum hourly steam rate of 572,900 pounds per hour (lb/hr) occurred on December 21, 2005. All data during the crop season was analyzed, but only the period with the highest steaming rate is presented in the table. This maximum steam rate was increased by approximately 10 percent in the permit revision application to provide a margin of safety, and results in a maximum steam rate of 633,000 lb/hr (1-hour average).

Comment 2. Startup: Please submit some operational data during a long startup indicating: load, oxygen, ammonia, injection rate, and CO/NO_x emissions. Are there "hot" startups and "cold" startups?

Response: Current startup is defined as ending when the boiler reaches 200,000 lb/hr steam or 6 hours after fuel is first fed to the boiler, whichever occurs first. However, this 6 hour period for startup was not based on actual boiler operation. Actual operational data, including steam rate, heat input, oxygen (O_2), wet O_2, urea injection rate, nitrogen oxide (NO_x), and carbon monoxide (CO) emissions, are presented in Table 2 for four long startup scenarios. In the table, the extra startup time is indicated by asterisks.

In the first scenario, which includes data from November 21, 2005, the steam rate, heat input, O_2, wet O_2, NO_x, and CO emissions do not stabilize until after 8 hours of operation. In this scenario, the boiler was down 2 hours before startup, which is considered a "hot" startup.

In the second scenario, which includes data from December 27-28, 2005, the steam rate, heat input, O_2, and wet O_2 do not stabilize until after 10 hours of operation. In addition, the CO emissions do not stabilize until after 11 hours of operation. In this scenario, the boiler was down 15 hours before startup, which is considered a "cold" startup.

In the third scenario, which includes data from March 14-15, 2006, the O_2 and wet O_2 do not stabilize until after 9 hours of operation, while the steam rate, heat input, and CO emissions do not stabilize until after 10 hours of operation. In this scenario, the boiler was down 12 hours before startup, which is considered a "cold" startup.

In the fourth scenario, which includes data from April 3-4, 2006, the O_2, wet O_2, and NO_x emissions do not stabilize until after 7 hours of operation, while the steam rate, heat input, and CO emissions do not stabilize until after 8 hours of operation. In this scenario, the boiler was down 6 hours before startup, which is considered a "cold" startup.

In each of the startup scenarios, a maximum startup time of 6 hours does not allow the boiler to reach normal operating levels. Boiler No. 8 does experience hot startups, as presented in the first scenario, however, most of the hot startups require the same amount of time to stabilize as the cold startups.

Comment 3. **Please identify the problems with the installed baghouses and provide additional details on the physical changes to the existing conveyor system. Define "Bagacillo". What does the Bagacillo cyclone control? Provide additional details on the design of the Bagacillo cyclone. Is there vendor information to support > 99.99% control?**

Response: The installed baghouses have become corroded and require continuous maintenance. Due to the wet bagasse, the baghouse filters become plugged and the baghouse pulses continuously in order to clean itself. The baghouses are not operating properly and not functioning the way they were designed. It is noted that these baghouses were voluntarily installed by U.S. Sugar, i.e., there was no regulatory requirement to install them. U.S. Sugar installed the baghouses as a test to determine if they could help reduce any dust from the conveyor transfer points.

The existing conveyor system is undergoing modifications that include enclosing the conveyors and transfer points, installing new conveyors, and upgrading the current conveyor belt design. The first physical change is enclosing the existing and new conveyors and transfer points. The second physical change is upgrading the current conveyor belt design. As explained in the application, as bagasse is transferred from one conveyor to another, the force from the dropped bagasse causes the belt to move up and down. This up and down movement causes the bagasse to be suspended in air instead of settling on the belt. The up and down motion will be curtailed by installing "landing zones" on each conveyor. A landing zone is a hard surface under the belt and at an angle along the sides of the belt. The landing zone will prevent the belt from moving vertically at each drop location and create a better enclosure for the conveyors.

Bagacillo is very fine bagasse. As bagasse is conveyed from the mill to the boilers via the bagasse conveyor, a portion of the bagasse is pneumatically pulled off the conveyor to a drum. As the bagasse enters the drum, air sucks off the smaller bagasse particles (i.e., bagacillo). The bagacillo is then pneumatically conveyed to the Boiling House. At the Boiling House, the bagacillo is separated from the conveying air stream by use of a cyclone. The conveying air is then discharged to the atmosphere. After the bagacillo material is collected in the cyclone, it is mixed with clarifier mud to be used as part of the cake material on the vacuum filters. The bagacillo cyclone is part of the pneumatic conveying system to recover material and is not utilized as a control device. A drawing of the original bagacillo cyclone is presented in Figure 1. Because the cyclones were installed in 1960, no vendor information is available.

<u>**June 30, 2006 Email**</u>

Comment 1. **The increase in steam production also resulted in an increase in the maximum heat input rate as well as the short-term emissions that formed the basis of the original Air Quality Analysis. In addition to the previous questions, we will also need a revised PSD netting analysis and Air Quality Analysis for the modification.**

Response: Because the boiler has been operating for less than 2 years (started up mid-March 05), it is classified as a "new emissions unit." [Rule 62-210.200(205)]. Further, under the definition of "baseline actual emissions" [Rule 62-210.200(35)], for a new emissions unit, the baseline actual emissions are equal to the unit's potential to emit, (except for determining the emissions increase due to the initial construction and operation of the unit). As a result, for determining prevention of significant deterioration (PSD) applicability, the unit's baseline actual emissions are equal to the unit's potential emissions. Since the annual potential emissions are not increasing as a result of the steam rate increase, the net increase in emissions is zero. However, a new Air Quality Analysis was performed for Boiler No. 8 with the revised emission rates and stack parameters. Because Boiler No. 8 is permitted to operate all year, the emissions were not separated for the crop versus off-crop seasons.

A source impact analysis was performed for particulate matter with diameter less than or equal to 10 micrometers (PM_{10}), sulfur dioxide (SO_2), CO, and NO_x emissions resulting from Boiler No. 8. For this analysis, the total emissions from Boiler No. 8 were modeled, reflective of the higher short-term steam production rates. The short-term emission factor for CO was reevaluated using CEMS data during normal operation (i.e., excluding startup, shutdown, and malfunctions). The maximum actual CO emission factor from Boiler No. 8 was approximately 30-percent lower than the emission factor used in the June 2006 permit revision application. A safety factor was then applied to the new CO emission factor, resulting in a CO emission actor of 3.0 lb/MMBtu. Revised application pages for CO are included with this RAI.

For the ambient air quality standard (AAQS) analysis, the future emissions of the Clewiston Mill were modeled together with background emission facilities (see Table 13). The total air quality concentration was estimated by adding the maximum concentrations from all modeled sources to a non-modeled background concentration. The maximum annual and short-term total air quality concentrations were then compared to the AAQS.

For the PSD Class II increment analysis, the PSD increment consuming and expanding sources at the Clewiston Mill site were modeled with background PSD consuming or expanding sources. The maximum annual and short-term concentrations were compared to the allowable PSD Class II increments.

The nearest PSD Class I area to the Clewiston Mill site is the Everglades National Park (NP), located about 102 kilometers (km) (60 miles) to the south. There are no other PSD Class I areas located within 200 km of the site. For the Boiler No. 8 project, a PSD Class I significant impact analysis was performed to determine the maximum predicted pollutant impacts at the Everglades NP. For any maximum pollutant impact that is above a PSD Class I significant impact level, a detailed modeling analysis must be performed to evaluate compliance with the allowable PSD Class I increments.

The selection of an air quality model to predict air quality impacts for the proposed project was based on the ability of the model to simulate impacts in areas surrounding the project site. The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was selected to address air quality impacts for the project. AERMOD dispersion model (Version 04300) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN).

The AERMOD model was used to predict the maximum pollutant concentrations for the project in nearby areas surrounding the Clewiston Mill. For this analysis, the EPA regulatory default options were used to predict all maximum impacts.

These options include:

- Final plume rise at all receptor locations
- Stack-tip downwash
- Buoyancy-induced dispersion
- Default wind speed profile coefficients
- Default vertical potential temperature gradients
- Calm wind processing

The CALPUFF model was used to assess impacts from the project at the PSD Class I area of the Everglades NP located about 102 km from the Clewiston Mill. The predicted concentrations were then compared to applicable PSD Class I significant impact levels.

Meteorological data used in the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at the Palm Beach International (PBI) Airport and twice-daily upper air soundings collected at the Florida International University (FIU) in Miami. Concentrations were predicted using 5 years of hourly meteorological data from 2001 through 2005. The NWS office at PBI is located approximately 82 km (51 miles) east of the Clewiston Mill site and is the closest primary weather station to the study area considered to have meteorological data representative of the site. The meteorological data from this NWS station have been used for numerous air modeling studies within the sugar industry and for the Clewiston Mill.

The data for these stations were developed by the FDEP and processed into a format that can be input to the AERMOD model using the meteorological preprocessor program AERMET.

Based on the building dimensions associated with buildings and structures at the plant, all stacks at the Clewiston Mill will comply with the good engineering practice (GEP) stack height regulations. However, these stacks are less than GEP height. Therefore, the potential for building downwash to occur was considered in the air modeling analysis for these stacks.

The building dimensions considered in the air modeling analysis for the Clewiston Mill are presented in Table 3. The location of the buildings and stacks can be found on the site plot plan (Figure 2). At the Clewiston Mill, one or more buildings can cause building downwash effects at several stacks. For the modeling analysis, direction-specific building dimensions are input for H_b and l_b for 36 radial directions, with each direction representing a 10-degree sector. All direction-specific building parameters were calculated with the Building Profile Input Program (BPIP) with the Plume Rise Enhancement (PRIME) downwash algorithm, Version 04274. The BPIP program was used to generate building data for the ISCST3 model input.

For predicting maximum concentrations in the vicinity of the Clewiston Mill, more than 4,000 receptors located at the Mill's restricted property line and at offsite receptors were used. The receptors were modeled using the Universal Transverse Mercator (UTM) coordinate system, Zone 17, North American Datum 1927 (NAD27).

The stack and operating parameters for Boiler No. 8 are presented in Table 4. To determine relative locations of predicted impacts, a model origin was assumed to be at the stack location for Boiler No. 4. The origin was assigned X and Y coordinates of 0.0 m each and east and north UTM coordinates of 506,128.2 and 2,956,936.3 km, respectively.

Nested Cartesian receptor grids were used in addition to discrete Cartesian receptors along the Mill fence line. The significant impact analysis used the following receptor spacing:

- 50-meter intervals along the fence line,
- 100-meter intervals beyond the fence line to 2 km from the Mill,

- 250-meter intervals from 2 to 5 km from the Mill,
- 500-meter intervals from 5 to 10 km from the Mill, and
- 1000-meter intervals from 10 to 15 km from the Mill.

Receptor elevations and hill scale heights for all receptors were obtained from 7.5-minute USGS Digital Elevation Model (DEM) data using the AERMOD terrain preprocessor program AERMAP, Version 04300.

Concentrations were also predicted at 251 receptors located at the PSD Class I area of the Everglades NP. The receptors used were a subset of the 901 Everglades NP receptors provided by the National Park Service (NPS). The subset includes all NPS boundary receptors and a reduced resolution for the interior section of the Everglades NP. Because the distance to the Everglades NP is over 100 km and the terrain is flat, the subset receptor grid is considered adequate for capturing maximum impacts at the Everglades NP.

The maximum future short-term emissions for the 1-hour and 24-hour averaging periods for Boiler No. 8 are presented in Table 5. The maximum future annual emissions are presented in Table 6. Emissions are shown for 100%, 75%, and 50% load conditions, as well as for the maximum 24-hour average steam rate.

Significant Impact Analysis

The maximum predicted SO_2, NO_2, PM_{10}, and CO concentrations from the future Boiler 8 only are compared to the EPA significant impact levels in Table 7 for different boiler load scenarios. The results demonstrate that the maximum predicted NO_2, PM_{10}, and CO concentrations are below the respective significant impact levels and additional air modeling analyses are not required for these pollutants. However, the maximum predicted SO_2 concentrations are above the significant impact levels. As a result, additional detailed air modeling analyses are required to determine compliance with the SO_2 AAQS and the allowable SO_2 PSD Class II increments.

A summary of the SO_2 facilities considered for inclusion in the AAQS and PSD Class II air modeling analysis is presented in Table 8. A detailed summary of the stack operation and emissions data of the SO_2 facilities included in the modeling analysis is presented in Table 9.

AAQS Analysis

The maximum SO_2 concentrations predicted for all sources from the screening and refined analyses are presented in Tables 10 and 11, respectively. The refined modeling results are added to a non-modeled background concentration to produce a total air quality concentration that can be compared with the AAQS.

As shown in Table 11, the maximum total 3-hour, 24-hour, and annual average SO_2 concentrations are predicted to be 88, 38 and 11 micrograms per cubic meter ($\mu g/m^3$), respectively. These concentrations are all below the respective AAQS of 1,300, 260, and 60 $\mu g/m^3$ for these averaging periods.

PSD Class II Increment Analyses

The maximum SO_2 concentrations predicted for the PSD sources from the screening and refined analyses are presented in Tables 12 and 13, respectively. Many of the maximum impacts occurred at or near the Clewiston Mill property boundary. Some occurred at the edge of the receptor grid, over 10 km away. This would indicate that the maximum impacts are due to a source other than the Clewiston Mill.

As presented in Table 13, the maximum 3-hour, 24-hour, and annual average SO_2 Class II increment consumption concentrations are predicted to be 39, 9, and <0 $\mu g/m^3$, respectively. These concentrations are below the respective allowable PSD Class II increments of 512, 91, and 20 $\mu g/m^3$ for these averaging periods.

PSD Class I Significant Impact Analysis

The maximum SO_2, NO_2 and PM_{10} concentrations predicted at the Everglades NP PSD Class I area for the future Boiler No. 8 are presented in Table 14. As shown, the maximum 3-hour, 24-hour, and annual average SO_2 concentrations are predicted to be 0.31, 0.08, and 0.003 $\mu g/m^3$, respectively. These concentrations are well below the respective PSD Class I significant impact levels 1.0, 0.2, and 0.1 $\mu g/m^3$, for these averaging periods. The maximum annual average NO_2 is predicted to be 0.003 $\mu g/m^3$, which is below the PSD Class I significant impact level of 0.1 $\mu g/m^3$. The maximum 24-hour and annual average PM_{10} concentrations are predicted to be 0.034 and 0.002 $\mu g/m^3$, respectively. These concentrations are well below the respective PSD Class I significant impact levels of 0.3 and 0.2 $\mu g/m^3$. Because Boiler No. 8's future impacts were below all the PSD Class I significant impact levels, more detailed modeling analyses were not required.

Boiler No. 8 originally had a wet control device (i.e., wet cyclone) prior to the electrostatic precipitator (ESP). Boiler maximum achievable control technology (MACT) regulations required U.S. Sugar to monitor ESP parameters under Subpart DDDDD to demonstrate ongoing compliance with the PM emission limit. However, U.S. Sugar is testing the feasibility of eliminating the water spray to the cyclones (water will still be used for sluicing collected ash from the cyclones). Until this issue is settled, the cyclones may be operated either wet or dry. Boiler MACT requires U.S. Sugar install an opacity monitor if a dry control device is used for PM control. Because U.S. Sugar would like to keep the ESP parameters in lieu of the opacity monitor, even if the cyclones are operated dry, U.S. Sugar is proposing an alternative monitoring plan for Boiler No. 8, as allowed under 40 CFR 63, Subpart A.

Instead of continuous opacity monitoring, U.S. Sugar is requesting the use of the following procedures for a wet control device in order to demonstrate compliance with the applicable emission limit for particulate matter when operating the cyclones as a dry control device.

1. Perform the performance test according to 40 CFR 63.7530(c) and Table 7 of Subpart DDDDD;
2. Determine the minimum operating limits established during the performance test by taking the 90th percentile of the lowest test run average secondary voltage and secondary current (or total power input) measured during the tests that demonstrate compliance with the applicable emission limit;

3. Maintain minimum secondary voltage and secondary current or total power input of the ESP (all based on a 3-hour average) at or above the operating limits established during the performance test; and
4. Follow the ESP maintenance schedule and procedures to ensure that the components are well maintained.

If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

cc: Ron Blackburn, FDEP South District
Don Griffin
Peter Briggs

DB/all

Enclosures

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APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff — 10/20/06

Signature — Date

(seal)

* Attach any exception to certification statement.

**** Board of Professional Engineers Certificate of Authorization #00001670**

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-8**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.92** feet
8. Exit Temperature: **315** °F	9. Actual Volumetric Flow Rate: **395,000** acfm	10. Water Vapor: **24** %

11. Maximum Dry Standard Flow Rate: **270,000** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on biomass firing at the maximum 24-hour heat input rate. Maximum standard flow rates are at 7-percent oxygen.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3,555.0** lb/hour **1,285** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **400 ppmvd @ 7% O_2, 30-day rolling average** Reference: **MACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 3.0 lb/MMBtu = 3,555.0 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 3.0 lb/MMBtu = 3,231.0 lb/hr

30-day rolling average based on 40 CFR 63, Subpart DDDDD:
400 ppmvd @ 7% O_2 x 270,000 dscfm @ 7% O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1,545.6/28) ft-lb_f/lb_m-°R ÷ 528°R = 470.6 lb/hr

Annual based on 30-day rolling average:
470.6 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 2,061.2 TPY

11. Potential Fugitive and Actual Emissions Comment:

Annual limit based on 12-month rolling total from Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **400 ppmvd @ 7% O_2**	4. Equivalent Allowable Emissions: **470.6** lb/hour **2,061.2** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT Limit, 40 CFR 63, Subpart DDDDD, Table 1. Limit based on 30-day rolling average.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1,285 TPY**	4. Equivalent Allowable Emissions: lb/hour **1,285** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit based on 12-month rolling total. Annual TPY includes periods of startup, shutdown, and malfunction (SSM).**	

<u>Allowable Emissions</u> Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

TABLES

TABLE 1
HISTORICAL MAXIMUM STEAM PRODUCTION RATE OF BOILER NO. 8

Hour	Steam Production (klbs) [a]
12/20/05 15:00	509.3
12/20/05 16:00	506.5
12/20/05 17:00	543.3
12/20/05 18:00	501.5
12/20/05 19:00	485.6
12/20/05 20:00	534.8
12/20/05 21:00	530.6
12/20/05 22:00	572.9
12/20/05 23:00	538.9
12/21/05 0:00	539.5
12/21/05 1:00	525.7
12/21/05 2:00	550.6
12/21/05 3:00	558.6
12/21/05 4:00	556.6
12/21/05 5:00	522.9
12/21/05 6:00	496.2
12/21/05 7:00	499.8
12/21/05 8:00	510.8
12/21/05 9:00	457.0
12/21/05 10:00	519.3
12/21/05 11:00	537.1
12/21/05 12:00	500.1
12/21/05 13:00	519.6
12/21/05 14:00	507.0
12/21/05 15:00	501.3
12/21/05 16:00	525.6
12/21/05 17:00	528.7
12/21/05 18:00	509.7
12/21/05 19:00	557.8
12/21/05 20:00	532.8
12/21/05 21:00	538.2
12/21/05 22:00	539.7
Maximum =	572.9

[a] Data represents the period of the highest steam production rate during the crop season (November 1, 2005 and April 10, 2006), which was obtained from the U.S. Sugar CEMS.

TABLE 2
LONG STARTUP OPERATIONAL DATA FOR USSC BOILER NO. 8

Hour	Operation Status*	Steam Production (klbs)	Heat Input (MMBtu)	O_2 (%)	Wet O_2 (%)	Urea Injection (gal)	NOx (lb/MMBtu)	CO (ppm @ 7% O_2)
11/21/05 5:00	Normal	374.4	702.8	6.8	5.8	39.6	0.17	100.4
11/21/05 6:00	Normal	368.2	690.4	6.9	5.8	41.3	0.17	96.8
11/21/05 7:00	Normal	412.2	767.9	5.4	4.6	45.1	0.15	47.4
11/21/05 8:00	Normal	316.9	588.6	7.1	6.1	29.9	0.14	49.2
11/21/05 9:00	Shutdown	150.9	160.5	9.3	7.9	15.3	0.23	900.1
11/21/05 10:00	Down	Down	Down	Down	Down	Down	Down	Down
11/21/05 11:00	Down	Down	Down	Down	Down	Down	Down	Down
11/21/05 12:00	Startup	0.0	16.3	19.2	18.2	Down	0.17	54.0
11/21/05 13:00	Startup	0.0	39.5	18.5	17.6	Down	0.14	155.8
11/21/05 14:00	Startup	3.1	5.2	17.8	16.9	Down	0.40*	192.4
11/21/05 15:00	Startup	77.6	124.7	15.6	14.5	4.7	0.20	928.7
11/21/05 16:00	Startup	51.2	38.9	14.3	13.1	2.2	0.37	2900.3
11/21/05 17:00	***	251.0	475.0	11.3	10.3	6.2	0.12	1224.2
11/21/05 18:00	***	191.6	206.3	8.3	Invalid	6.8	Invalid	533.7
11/21/05 19:00	***	205.3	299.5	12.4	Invalid	4.4	Invalid	1183.1
11/21/05 20:00	Normal	324.8	608.2	6.4	5.2	5.4	0.11	421.7
11/21/05 21:00	Normal	328.2	613.7	7.0	5.8	8.8	0.12	304.0
11/21/05 22:00	Normal	310.9	581.4	7.1	5.9	0.9	0.11	174.9
11/21/05 23:00	Normal	350.5	658.3	6.3	5.2	4.5	0.09	386.2
12/27/05 16:00	Down	Down	Down	Down	Down	Down	Down	Down
12/27/05 17:00	Down	Down	Down	Down	Down	Down	Down	Down
12/27/05 18:00	Down	Down	Down	Down	Down	Down	Down	Down
12/27/05 19:00	Startup	0.0	48.1	19.4	18.9	Down	0.24	120.5
12/27/05 20:00	Startup	0.0	88.7	19.6	19.2	Down	0.14	140.1
12/27/05 21:00	Startup	0.0	56.3	19.5	19.0	Down	0.24	146.0
12/27/05 22:00	Startup	0.0	56.2	19.5	19.1	Down	0.24	113.2
12/27/05 23:00	Startup	0.0	85.7	19.8	19.4	Down	0.13	130.2
12/28/05 0:00	Startup	0.0	79.6	19.9	19.6	Down	0.09	129.3
12/28/05 1:00	***	0.0	107.3	19.0	18.5	Down	0.10	159.5
12/28/05 2:00	***	32.8	58.9	17.0	16.2	Down	0.29	204.2
12/28/05 3:00	***	121.1	227.8	15.3	14.0	Down	0.13	2153.3
12/28/05 4:00	***	150.1	279.1	12.4	12.2	2.6	0.09	3014.7
12/28/05 5:00	***	418.4	795.3	4.0	4.3	25.8	Inval	1498.9
12/28/05 6:00	Normal	453.1	857.3	5.7	5.6	27.1	0.19	334.7
12/28/05 7:00	Normal	441.0	831.6	6.2	5.7	27.4	0.20	342.0
12/28/05 8:00	Normal	407.0	765.9	6.6	7.1	20.8	Inval	333.7
12/28/05 9:00	Normal	436.9	820.2	6.0	6.2	26.8	Inval	334.5
3/14/06 22:00	Down	Down	Down	Down	Down	Down	Down	Down
3/14/06 23:00	Down	Down	Down	Down	Down	Down	Down	Down
3/15/06 0:00	Down	Down	Down	Down	Down	Down	Down	Down
3/15/06 1:00	Startup	0.4	33.6	20.0	19.3	Down	0.07	65.1
3/15/06 2:00	Startup	0.4	51.7	20.5	19.8	Down	0.03	33.7
3/15/06 3:00	Startup	0.4	58.5	19.6	18.9	Down	0.14	51.2
3/15/06 4:00	Startup	0.4	70.0	20.0	19.2	Down	0.06	104.6
3/15/06 5:00	Startup	0.4	100.4	17.7	16.9	Down	0.19	120.3
3/15/06 6:00	Startup	0.3	105.9	17.5	16.7	Down	0.21	143.9
3/15/06 7:00	***	0.3	79.7	19.2	18.3	Down	0.17	153.7
3/15/06 8:00	***	110.9	208.8	15.5	14.5	0.5	0.12	156.8
3/15/06 9:00	***	271.1	517.9	7.9	6.9	7.4	0.13	428.9
3/15/06 10:00	***	342.1	650.0	5.2	4.2	2.6	0.11	665.5
3/15/06 11:00	Normal	425.7	808.8	5.5	4.4	32.3	0.13	372.4
3/15/06 12:00	Normal	464.8	890.2	4.9	3.8	34.3	0.13	303.2
3/15/06 13:00	Normal	491.8	939.7	4.4	3.5	42.8	0.13	482.3
3/15/06 14:00	Normal	456.5	875.8	4.9	3.8	37.5	0.12	586.7
3/15/06 15:00	Normal	489.7	937.2	4.3	3.4	43.3	0.13	475.1
3/15/06 16:00	Normal	481.3	919.0	4.7	3.7	32.6	0.13	335.6
3/15/06 17:00	Normal	507.5	972.4	5.0	3.8	51.5	0.13	253.9
3/15/06 18:00	Normal	511.3	981.7	4.6	3.6	56.0	0.14	252.1
4/3/06 2:00	Normal	489.2	918.2	5.2	4.1	39.9	0.13	243.3
4/3/06 3:00	Normal	501.2	938.1	5.0	3.9	53.5	0.13	244.2
4/3/06 4:00	Normal	507.0	946.6	5.1	3.9	32.2	0.13	308.4
4/3/06 5:00	Normal	479.0	901.0	5.8	4.5	30.0	0.13	275.7
4/3/06 6:00	Normal	507.7	956.0	5.1	4.0	46.1	0.13	263.2
4/3/06 7:00	Shutdown	288.5	534.4	9.2	8.0	20.3	0.14	196.7
4/3/06 8:00	Down	0.4	Down	21.0	20.3	Down	Down	119.2
4/3/06 9:00	Down	0.3	Down	Down	Down	Down	Down	Down
4/3/06 10:00	Down	0.5	Down	Down	Down	Down	Down	Down
4/3/06 11:00	Down	0.4	Down	Down	Down	Down	Down	Down
4/3/06 12:00	Down	0.4	Down	Down	Down	Down	Down	Down
4/3/06 13:00	Down	0.4	Down	Down	Down	Down	Down	Down
4/3/06 14:00	Startup	0.3	40.1	19.8	19.1	Down	0.11	60.7
4/3/06 15:00	Startup	0.2	61.6	19.0	18.3	Down	0.18	96.6
4/3/06 16:00	Startup	0.2	57.8	19.1	18.4	Down	0.25	62.9
4/3/06 17:00	Startup	0.3	59.3	19.1	18.2	Down	0.22	86.3
4/3/06 18:00	Startup	0.3	55.8	19.2	18.4	Down	0.16	110.5
4/3/06 19:00	Startup	0.3	85.4	18.9	18.1	Down	0.16	150.1
4/3/06 20:00	***	45.4	82.0	16.5	15.3	Down	0.26	668.5
4/3/06 21:00	***	353.7	671.8	3.5	2.6	0.6	0.09	3317.5
4/3/06 22:00	Normal	415.2	777.9	5.5	4.4	33.8	0.14	292.9
4/3/06 23:00	Normal	450.9	843.0	5.2	4.0	34.2	0.12	343.0
4/4/06 0:00	Normal	469.3	876.7	5.1	3.9	42.4	0.15	311.5
4/4/06 1:00	Normal	431.9	807.1	5.6	4.3	33.4	0.13	293.8
4/4/06 2:00	Normal	427.4	798.5	5.7	4.5	28.0	0.13	310.7

Source: Data obtained from the U.S. Sugar CEMS.

* Startup is defined as ending when the boiler reaches 200,000 lb/hr steam or the first 6 hours of operation, whichever occurs first.
Shutdown is defined as beginning when the fuel feed is terminated (1 hour before going down).

*** Refers to a long startup condition based on either the steam production, heat input, oxygen, urea, or emissions data.

TABLE 3
SUMMARY OF BUILDING STRUCTURES CONSIDERED IN THE AIR MODELING ANALYSIS

Structure	Height		Length		Width	
	ft	m	ft	m	ft	m
Boiler No. 8 Structures						
Boiler No. 8 Building	98.0	29.9	92.0	28.0	58.8	17.9
Boiler No. 8 ESP	69.0	21.0	69.6	21.2	46.6	14.2
Mill Expansion Buildings						
Electrical Equipment	100.0	30.5	95.6	29.1	27.6	8.4
Support Structure	130.0	39.6	95.6	29.1	76.2	23.2
Dryer Area	100.0	30.5	95.6	29.1	39.0	11.9
Screening & Distribution Towers	150.0	45.7	126.4	38.5	68.7	20.9
Specialty Packaging Facility	40.0	12.2	82.1	25.0	201.6	61.4
Packaging Facility	40.0	12.2	65.0	19.8	280.0	85.3
Warehouse	28.0	8.5	339.7	103.5	289.7	88.3
Electrical & Conditioning Equipment	24.0	7.3	59.7	18.2	52.3	15.9
Bulk Loading	40.0	12.2	84.4	25.7	53.8	16.4
Sugar Silos	136.0	41.5	111.6	34.0	68.1	20.8
Other Mill Buildings						
Pellet Warehouse	46.0	14.0	527.0	160.6	105.0	32.0
WDA	51.0	15.5	55.0	16.8	53.0	16.2
Storage and Safety mechanic	34.8	10.6	58.0	17.7	52.0	15.8
Boiler No. 4 Building	87.5	26.7	78.0	23.8	66.0	20.1
Boiler No. 5&6 Building	56.0	17.1	118.0	36.0	66.0	20.1
Boiler No. 1&2 Building	67.3	20.5	115.0	35.1	103.0	31.4
Power House	34.0	10.4	119.0	36.3	65.0	19.8
C-Tandem	82.0	25.0	209.5	63.9	97.4	29.7
Evaporators	100.0	30.5	186.2	56.8	139.7	42.6
B Mill Building	68.0	20.7	178.0	54.3	81.0	24.7
A Mill Building	69.0	21.0	243.0	74.1	67.0	20.4
Boiling House	93.7	28.6	181.0	55.2	155.0	47.2
Boiler No. 7 ESP	87.5	26.7	55.0	16.8	33.0	10.1
Boiler No. 7 Building	93.0	28.3	83.0	25.3	68.0	20.7
Sugar Warehouse #1	37.0	11.3	390.5	119.0	103.8	31.6
Sugar Warehouse #3	63.0	19.2	122.4	37.3	98.3	30.0
Clarifiers	56.0	17.1	772.3	235.4	144.4	44.0
Central Control Room	20.0	6.1	208.7	63.6	103.3	31.5
Cooling Tower	53.0	16.2	76.5	23.3	52.5	16.0
B_CPVS	100.0	30.5	74.9	22.8	50.4	15.4

TABLE 4
STACK AND OPERATING PARAMETERS USED IN THE BOILER NO. 8 MODELING ANALYSIS, U.S. SUGAR, CLEWISTON MILL

Emission Unit	Model ID	Load	UTM Coordinates [a] East (m)	UTM Coordinates [a] North (m)	Stack Data [b] Height (ft)	Stack Data [b] Height (m)	Stack Data [b] Diameter (ft)	Stack Data [b] Diameter (m)	Heat Input (MMBtu/hr)	Operating Data [b] Temperature (°F)	Operating Data [b] Temperature (°K)	Operating Data [b] Gas Flow (acfm)	Operating Data [b] Velocity (ft/s)	Operating Data [b] Velocity (m/s)
Maximum Permitted - Crop/Off-Crop Season														
Boiler No. 8	BLR8	100%	506,046.2	2,956,987.3	199	60.7	10.92	3.33	1,185	315	430	434,610	77.3	23.57
Boiler No. 8	BLR8	75%	506,046.2	2,956,987.3	199	60.7	10.92	3.33	889	315	430	325,958	58.0	17.68
Boiler No. 8	BLR8	50%	506,046.2	2,956,987.3	199	60.7	10.92	3.33	593	315	430	217,305	38.7	11.79

[a] Universal transverse coordinates, zone 17.

[b] Stack and operating data based on air construction permit application dated June 2006.

TABLE 5
MAXIMUM SHORT-TERM EMISSIONS FOR BOILER NO. 8, U.S. SUGAR, CLEWISTON MILL

Emission Unit	Model ID	Load	Heat Input (MMBtu/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)
Maximum Permitted - Crop/Off-Crop Season							
Boiler No. 8[a]	BLR8	100%	1,185	29.63	71.10	355.5	3,555.0
Boiler No. 8	BLR8	24-hr	1,077	26.93	64.62	--	--
Boiler No. 8	BLR8	75%	889	22.22	53.33	266.6	2,666.3
Boiler No. 8	BLR8	50%	593	14.82	35.55	177.8	1,777.5

[a] Emissions based on air construction permit application dated June 2006, except for CO.

TABLE 6
MAXIMUM ANNUAL EMISSIONS FOR BOILER NO. 8, U.S. SUGAR, CLEWISTON MILL

Emission Unit	Model ID	PM_{10} (TPY)	SO_2 (TPY)	NO_x (TPY)	CO (TPY)
Boiler No. 8[a]	BLR8	84.6	203.0	473.7	1,285

TPY= tons per year
[a] Emissions based on air construction permit application dated June 2006.

TABLE 7
MAXIMUM IMPACTS PREDICTED FOR COMPARISON TO EPA SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Emission Rate by Load (lb/hr)			Maximum Concentration[a] by Load ($\mu g/m^3$)			EPA Significant Impact Levels ($\mu g/m^3$)
		Base Load	75% Load	50% Load	Base Load	75% Load	50% Load	
Generic (10 g/s)	Annual	79.365	79.365	79.365	0.9221	1.1019	1.4537	
	High 24-Hour	79.365	79.365	79.365	7.6697	9.3252	11.3699	
	High 8-Hour	79.365	79.365	79.365	9.4277	10.9285	13.1911	
	High 3-Hour	79.365	79.365	79.365	10.4227	12.2276	15.0204	
	High 1-Hour	79.365	79.365	79.365	10.8790	12.8422	16.4112	
SO_2	Annual	46.35	34.76	23.17	0.54	0.48	0.42	1
	High 24-Hour	64.62	48.47	32.31	6.24	5.69	4.63	5
	High 3-Hour	71.10	53.33	35.55	9.34	8.22	6.73	25
PM_{10}	Annual	19.32	14.49	9.66	0.22	0.20	0.18	1
	High 24-Hour	26.93	20.20	13.47	2.60	2.37	1.93	5
NO_2[b]	Annual	108.15	81.11	54.08	0.94	0.84	0.74	1
CO	High 8-Hour	3555.0	2666.3	1777.5	422.3	367.1	295.4	500
	High 1-Hour	3555.0	2666.3	1777.5	487.3	431.4	367.6	2000

[a] Based on the AERMOD model using 5 years of surface and upper air meteorological data from 2001 to 2005 from the NWS station at Palm Beach International Airport and Florida International University in Miami, respectively.
[b] NO_2 concentration is assumed equal to 75 percent of NO_X concentration

TABLE 8

SUMMARY OF SO_2 FACILITIES CONSIDERED FOR INCLUSION IN THE AAQS AND PSD CLASS II AIR MODELING ANALYSES

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Palm Beach Power [a] X (km)	Y (km)	Distance (km)	Direction (deg)	Maximum SO_2 Emissions (TPY)	Q, Emission Threshold [b] (Dist - SIA) x 20	Include in Modeling Analysis ?
0990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	17.3	-1.7	17.4	96	98	147.7	NO
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-18.5	0.7	18.5	272	173	170.3	YES
na	Glades Electric Cooperative	Hendry	487.1	2957.5	-19.0	0.6	19.0	272	40	180.7	NO
0430008	Atlas-Transoil Inc - South FL Thermal Serv	Hendry	489.2	2966.6	-16.9	9.7	19.5	300	85	189.7	NO
0990332	New Hope Power Partnership (Okeelanta)	Palm Beach	524.1	2940.0	18.0	-16.9	24.7	133	1,999	293.8	YES
0990005	Okeelanta	Palm Beach	525.0	2937.4	18.9	-19.5	27.2	136	51	343.1	NO
0510003	Sugar Cane Growers	Palm Beach	534.9	2953.3	28.8	-3.6	29.0	97	2,555	380.5	YES
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.1	31.7	12.2	34.0	69	2,698	479.3	YES
0990019	Osceola Farms	Palm Beach	544.2	2968.0	38.1	11.1	39.7	74	1,467	593.7	YES
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	46.8	-11.7	48.2	104	954	764.8	YES
0990349	South Florida WMD--Pump Stn. G-310/S-6	Palm Beach	554.2	2940.5	48.1	-16.4	50.8	109	5	816.4	NO
0850001	FPL - Martin	Martin	543.1	2992.9	37.0	36.0	51.6	46	22,982	832.5	YES
0850102	Indiantown Cogeration	Martin	545.6	2991.5	39.5	34.6	52.5	49	2,629	850.2	YES
0990021	Pratt & Whitney (United Technologies)	Palm Beach	562.0	2960.0	55.9	3.1	56.0	87	1,390	919.7	YES
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	44.8	61.2	75.8	36	76	1316.9	NO
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	79.7	3.3	79.8	88	1,533	1395.4	NO
0710019	Lee County Resource Recovery	Lee	424.2	2945.7	-81.9	-11.2	82.7	262	163	1453.2	NO
0710000	FPL - Fort Myers [c]	Lee	422.1	2952.9	-84.0	-4.0	84.1	267	22,702	1481.9	YES
0850021	Stuart Contracting	Martin	575.2	3006.8	69.1	49.9	85.2	54	100	1504.7	NO
0990045	Lake Worth Utilities	Palm Beach	592.8	2943.7	86.7	-13.2	87.7	99	7,415	1554.0	NO
0990568	Lake Worth Generating	Palm Beach	592.8	2943.7	86.7	-13.2	87.7	99	54	1554.0	NO
0990042	FPL -Riviera Beach [c]	Palm Beach	594.2	2960.6	88.1	3.7	88.2	88	73,475	1563.6	YES
0550018	TECO-Phillips	Highlands	464.3	3035.4	-41.8	78.5	88.9	332	4,053	1578.7	NO
0990350	South Florida WMD--Pump Stn. S-9	Broward	555.9	2882.2	49.8	-74.7	89.8	146	2	1595.1	NO
0112534	Enron/Deerfield Beach Energy Center	Broward	583.1	2907.9	77.0	-49.0	91.3	122	166	1625.4	NO
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	77.2	-48.9	91.4	122	87	1627.7	NO
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	77.5	-49.3	91.9	122	896	1637.0	NO
0112515	Enron/Pompano Energy Center	Broward	583.7	2905.5	77.6	-51.4	93.1	124	166	1661.6	NO
1110003	Fort Pierce Utilities	St. Lucie	566.8	3036.3	60.7	79.4	99.9	37	1,497	1798.9	NO
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	73.5	-73.6	104.0	135	1,318	1880.3	NO
0110037	FPL -Lauderdale [c]	Broward	580.1	2883.3	74.0	-73.6	104.4	135	47,858	1887.4	YES
0110036	FPL -Port Everglades [c]	Broward	587.4	2885.3	81.3	-71.6	108.3	131	170,215	1966.7	YES
0250020	Titan (Tarmac)	Dade	562.9	2861.7	56.8	-95.2	110.9	149	2,792	2017.1	NO
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	58.2	-99.5	115.3	150	857	2105.4	NO
0610029	Vero Beach Power [c]	St. Lucie	567.1	3056.5	61.0	99.6	116.8	31	10,274	2135.9	YES

Note: deg = degrees
km = kilometers
TPY = tons per year

[a] U.S. Sugar Corporation Clewiston Mill' East and North Coordinates (km) are: 506.1 and 2956.9 , respectively.

[b] Based on North Carolina Screening Technique for annual average basis. "Dist" is the distance the facility is located from the project. "SIA" is the significant impact area. The project's 24-hour SO_2 concentrations are assumed significant out to 10 km from the project.

[c] Large source with annual emissions greater than 10,000 TPY located beyond the screening area (60 km) that were included in the inventory.

TABLE 9
DETAILED SUMMARY OF STACK, OPERATING, AND EMISSIONS DATA OF FACILITIES WITH SO_2 EMISSIONS INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

AIRS Number	Facility Units	Modeling ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Emission Rate 3-Hour lb/hr	Emission Rate 3-Hour g/s	Emission Rate 24-Hour lb/hr	Emission Rate 24-Hour g/s	PSD Source (EXP/CON)	Modeled in AAQS	Modeled in Class II
0510003	US Sugar - Clewiston [c]																		
	<u>PSD Baseline (On-crop season only)</u>																		
	Unit 1 PSD Baseline	USSBRL1B	506.2	2,956.9	75.8	23.1	6.1	1.86	160	344	99.0	30.20	-633.8	-79.86	-462.0	-58.21	EXP	No	Yes
	Unit 2 PSD Baseline	USSBLR2B	506.2	2,956.9	75.8	23.1	6.1	1.86	158	343	117.0	35.70	-633.8	-79.86	-462.0	-58.21	EXP	No	Yes
	Unit 3 PSD Baseline	USSBLR3B	506.2	2,956.9	90.0	27.4	7.5	2.29	156	342	48.2	14.70	-383.3	-48.30	-263.5	-33.20	EXP	No	Yes
	East Pellet Plant PSD Baseline	EPELLET	506.1	2,957.0	40.0	12.2	5.0	1.52	165	347	28.0	8.54	-81.7	-10.30	-81.7	-10.30	EXP	No	Yes
	West Pellet Plant PSD Baseline	WPELLET	506.1	2,957.0	51.5	15.7	5.0	1.52	165	347	28.0	8.54	-81.7	-10.30	-81.7	-10.30	EXP	No	Yes
	<u>On-crop season future</u>																		
	Unit 1	USSBRL1N	506.2	2,956.9	213.0	64.9	8.0	2.44	150	339	82.9	25.30	29.8	3.75	29.8	3.75	CON	Yes	Yes
	Unit 2	USSBLR2N	506.2	2,956.9	213.0	64.9	8.0	2.44	150	339	82.9	25.30	26.8	3.38	26.8	3.38	CON	Yes	Yes
	Unit 4	USSBLR4N	506.1	2,956.9	150.0	45.7	8.2	2.50	160	344	88.7	27.00	38.0	4.79	36.0	4.54	CON	Yes	Yes
	Unit 7	USSBLR7N	506.1	2,957.0	225.0	68.6	8.0	2.44	335	441	94.5	28.80	138.0	17.39	125.5	15.81	CON	Yes	Yes
	Unit 8	USSBLR8N	506.0	2,957.0	199.0	60.7	10.9	3.33	315	430	77.3	23.57	71.1	8.96	64.6	8.14	CON	Yes	Yes
	<u>Off-crop season future</u>																		
	Unit 7	USSBLR7F	506.1	2,957.0	225.0	68.6	8.0	2.44	335	441	94.5	28.80	138.0	17.39	125.5	15.81	CON	Yes	Yes
0510015	Southern Gardens Citrus - PSD																		
	Peel Dryers 1-2	SGARDDRY	487.6	2957.6	125.0	38.1	5.7	1.74	109	316	24.4	7.45	21.0	2.65	21.0	2.65	CON	Yes	Yes
	Boilers 1-4	SGARDBLR	487.6	2957.6	55.0	16.8	4.0	1.22	400	478	46.7	14.22	5.8	0.73	5.8	0.73	CON	Yes	Yes
0990086	New Hope Power Partnership (Okeelanta)																		
	Okeelanta Power Blrs 1,2,3 [b]	OKCOGENF	524.1	2,940.0	199.0	60.7	10.0	3.05	352	451	63.6	19.39	456.3	57.5	456.3	57.5	CON	Yes	Yes
0990016	Sugar Cane Growers [c]																		
	BOILER #1 Future On-crop season	SCG1N	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	58.7	17.90	603.1	75.99	603.1	75.99	CON	Yes	Yes
	BOILER #2 Future On-crop season	SCG2N	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	70.2	21.41	603.1	75.99	603.1	75.99	CON	Yes	Yes
	BOILER #3 Future On-crop season	SCG3N	534.9	2,953.3	180.0	54.9	6.9	2.11	150	339	54.9	16.74	412.8	52.01	412.8	52.01	CON	No	No
	BOILER #4 Future On-crop season	SCG4N	534.9	2,953.3	180.0	54.9	9.4	2.88	150	339	63.3	19.28	1031.9	130.02	1031.9	130.02	CON	No	No
	BOILER #5Future On-crop season	SCG5N	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	92.2	28.10	792.8	99.89	792.8	99.89	CON	No	No
	BOILER #8 Future On-crop season	SCG8N	534.9	2,953.3	155.0	47.2	9.5	2.90	150	339	49.7	15.16	394.4	49.69	394.4	49.69	CON	No	No
	Note: Only SCBLR1N and SCBLR2N were modeleded due to 14 TPD limit																		
	BOILER #1 Future Off-crop season	SCG1F	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	58.7	17.90	355.6	44.80	255.6	32.20	CON	Yes	Yes
	BOILER #4 Future Off-crop season	SCG4F	534.9	2,953.3	180.0	54.9	9.4	2.88	150	339	63.3	19.28	607.9	76.60	34.1	4.30	CON	Yes	Yes
	BOILER #1 PSD Baseline Off-crop season	SCG1BF	534.9	2,953.3	79.1	24.1	5.5	1.68	395	475	52.3	15.94	-236.5	-29.80	-236.5	-29.80	EXP	No	Yes
	BOILER #2 PSD Baseline Off-crop season	SCG2BF	534.9	2,953.3	79.1	24.1	5.5	1.68	405	480	58.7	17.88	-236.5	-29.80	-236.5	-29.80	EXP	No	Yes
	BOILER #3 PSD Baseline Off-crop season	SCG3BF	534.9	2,953.3	79.1	24.1	5.5	1.68	470	517	54.1	16.50	-177.8	-22.40	-177.8	-22.40	EXP	No	Yes
	BOILER #4 PSD Baseline Off-crop season	SCG4BF	534.9	2,953.3	86.0	26.2	5.3	1.62	149	338	32.4	9.88	-205.6	-25.90	-205.6	-25.90	EXP	No	Yes
	BOILER #5 PSD Baseline Off-crop season	SCG5BF	534.9	2,953.3	79.1	24.1	6.7	2.03	490	528	93.2	28.42	-315.1	-39.70	-315.1	-39.70	EXP	No	Yes
	BOILER #6 PSD Baseline Off-crop season	SCG6BF	534.9	2,953.3	40.0	12.2	5.0	1.52	630	605	21.4	6.53	-147.6	-18.60	-147.6	-18.60	EXP	No	Yes
	BOILER #7 PSD Baseline Off-crop season	SCG7BF	534.9	2,953.3	40.0	12.2	5.0	1.52	630	606	56.4	17.20	-354.0	-44.60	-354.0	-44.60	EXP	No	Yes
	BOILER #1 PSD Baseline On-crop season	SCG1BN	534.9	2,953.3	79.1	24.1	5.5	1.68	395	475	52.3	15.94	-150.0	-18.90	-150.0	-18.90	EXP	No	Yes

TABLE 9

DETAILED SUMMARY OF STACK, OPERATING, AND EMISSIONS DATA OF FACILITIES WITH SO_2 EMISSIONS INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

AIRS Number	Facility	Units	Modeling ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Emission Rate 3-Hour lb/hr	Emission Rate 3-Hour g/s	Emission Rate 24-Hour lb/hr	Emission Rate 24-Hour g/s	PSD Source (EXP/CON)	Modeled in AAQS	Modeled in Class II
		BOILER #2 PSD Baseline On-crop season	SCG2BN	534.9	2,953.3	79.1	24.1	5.5	1.68	405	480	58.7	17.88	-150.0	-18.90	-150.0	-18.90	EXP	No	Yes
		BOILER #3 PSD Baseline On-crop season	SCG3BN	534.9	2,953.3	79.1	24.1	5.5	1.68	470	517	54.1	16.50	-112.7	-14.20	-112.7	-14.20	EXP	No	Yes
		BOILER #4 PSD Baseline On-crop season	SCG4BN	534.9	2,953.3	86.0	26.2	5.3	1.62	149	338	32.4	9.88	-205.6	-25.90	-205.6	-25.90	EXP	No	Yes
		BOILER #5 PSD Baseline On-crop season	SCG5BN	534.9	2,953.3	79.1	24.1	6.7	2.03	490	528	93.2	28.42	0.0	0.00	0.0	0.00	EXP	No	Yes
		BOILER #6 PSD Baseline On-crop season	SCG6BN	534.9	2,953.3	40.0	12.2	5.0	1.52	630	605	21.4	6.53	0.0	0.00	0.0	0.00	EXP	No	Yes
		BOILER #7 PSD Baseline On-crop season	SCG7BN	534.9	2,953.3	40.0	12.2	5.0	1.52	630	606	56.4	17.20	-121.4	-15.30	-121.4	-15.30	EXP	No	Yes
0990061	US Sugar-Bryant [a]																			
		Boiler No 5	USSBRY5	537.8	2,969.1	150.0	45.7	9.5	2.90	161	345	37.7	11.49	613.1	77.25	613.1	77.25	CON	Yes	No
		Boilers No 1,2&3	USBRY123	537.8	2,969.1	65.0	19.8	5.4	1.64	156	342	119.4	36.40	1585.0	199.71	1585.0	199.71	CON	Yes	No
		Diesel Electric Generator Pt 07	USSBRY07	537.8	2,969.1	28.0	8.5	1.2	0.37	475	519	40.0	14.76	28.0	8.41	66.7	8.41	CON	Yes	Yes
		Diesel Electric Generator Pt 08	USSBRY08	537.8	2,969.1	28.0	8.5	1.2	0.37	475	519	42.0	12.19	29.0	8.90	70.6	8.90	CON	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	537.8	2,969.1	65.0	19.8	5.5	1.68	430	494	145.3	44.30	-289.7	-36.50	-289.7	-36.50	EXP	No	Yes
		Unit 2&3 PSD Baseline	USBRY23B	537.8	2,969.1	65.0	19.8	5.5	1.68	160	344	124.3	37.90	-579.4	-73.00	-579.4	-73.00	EXP	No	Yes
0990019	Osceola Farms PSD Baseline [a]																			
		Unit 2	OSBLR2	544.2	2,968.0	90.0	27.4	5.0	1.52	154	341	51.9	15.82	135.9	17.12	46.6	5.87	CON	Yes	Yes
		Unit 3	OSBLR3	544.2	2,968.0	90.0	27.4	6.3	1.91	156	342	55.3	16.86	244.0	30.74	50.7	6.39	CON	Yes	Yes
		Unit 4	OSBLR4	544.2	2,968.0	90.0	27.4	6.0	1.83	154	341	54.7	16.67	100.8	12.70	99.3	12.51	CON	Yes	Yes
		Unit 5a	OSBLR5A	544.2	2,968.0	90.0	27.4	5.0	1.52	154	341	54.1	16.48	50.2	6.33	49.7	6.26	CON	Yes	Yes
		Unit 5b	OSBLR5B	544.2	2,968.0	90.0	27.4	5.0	1.52	154	341	54.1	16.48	50.2	6.33	49.7	6.26	CON	Yes	Yes
		Unit 6	OSBLR6	544.2	2,968.0	90.0	27.4	6.2	1.88	154	341	59.7	18.19	265.0	33.39	16.5	2.08	CON	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	544.2	2,968.0	72.2	22.0	5.0	1.52	156	342	59.6	18.18	-40.2	-5.07	-40.2	-5.07	EXP	No	Yes
		Unit 2 PSD Baseline	OSBLR2B	544.2	2,968.0	72.2	22.0	5.0	1.52	154	341	59.4	18.10	-129.5	-16.32	-129.5	-16.32	EXP	No	Yes
		Unit 3 PSD Baseline	OSBLR3B	544.2	2,968.0	72.2	22.0	6.3	1.93	154	341	47.6	14.50	-57.6	-7.26	-57.6	-7.26	EXP	No	Yes
		Unit 4 PSD Baseline	OSBLR4B	544.2	2,968.0	72.2	22.0	6.0	1.83	154	341	61.7	18.80	-108.0	-13.61	-108.0	-13.61	EXP	No	Yes
0990016	Atlantic Sugar [a]																			
		Unit 1	ATLSUG1	552.9	2,945.2	90.0	27.4	6.0	1.83	163	346	59.0	17.97	129.2	16.28	129.2	16.28	CON	Yes	Yes
		Unit 2	ATLSUG2	552.9	2,945.2	90.0	27.4	6.0	1.83	170	350	76.6	23.36	129.2	16.28	129.2	16.28	CON	Yes	Yes
		Unit 3	ATLSUG3	552.9	2,945.2	90.0	27.4	6.0	1.83	170	350	70.7	21.56	127.1	16.02	127.1	16.02	CON	Yes	Yes
		Unit 4	ATLSUG4	552.9	2,945.2	90.0	27.4	6.0	1.83	160	344	82.5	25.16	128.7	16.21	128.7	16.21	CON	Yes	Yes
		Unit 5 PSD [b]	ATLSUG5	552.9	2,945.2	90.0	27.4	5.5	1.68	151	339	63.1	19.24	66.7	8.41	63.8	8.04	CON	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	552.9	2,945.2	62.0	18.9	6.3	1.92	451	506	41.7	12.70	-136.8	-17.24	-136.8	-17.24	EXP	No	Yes
		Unit 2 PSD Baseline	ATLSUG2B	552.9	2,945.2	62.0	18.9	6.3	1.92	460	511	35.8	10.90	-178.6	-22.50	-178.6	-22.50	EXP	No	Yes
		Unit 3 PSD Baseline	ATLSUG3B	552.9	2,945.2	71.8	21.9	6.0	1.83	480	522	57.4	17.50	-134.0	-16.88	-134.0	-16.88	EXP	No	Yes
		Unit 4 PSD Baseline	ATLSUG4B	552.9	2,945.2	60.0	18.3	6.0	1.83	160	344	49.2	15.00	-85.4	-10.76	-85.4	-10.76	EXP	No	Yes
990021	Pratt & Whitney (United Technologies)																			
		Heater	PRATARCH	562.0	2960.0	50.0	15.2	3.0	0.91	1000	811	471.6	143.73	111.0	13.99	111.0	13.99	CON	No	No
		Boiler BO-12, -1, -2, -14, -3	PRATBO12	562.0	2,960.0	15.0	4.6	2.5	0.76	500	533	22.7	6.92	0.1	0.012	0.1	0.012	CON	No	No
0850001	FPL Martin																			
		Units 1&2	MART12	543.1	2,992.9	499.0	152.1	26.2	7.99	298	421	69.0	21.03	13839.6	1743.79	13839.6	1743.79	NO	Yes	No
		Units 3&4 PSD	MART34	543.1	2,992.9	213.0	64.9	20.0	6.10	280	411	62.0	18.90	3733.3	470.40	3733.3	470.40	CON	Yes	Yes

TABLE 9
DETAILED SUMMARY OF STACK, OPERATING, AND EMISSIONS DATA OF FACILITIES WITH SO_2 EMISSIONS INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

AIRS Number	Facility Units	Modeling ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack and Operating Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Emission Rate 3-Hour lb/hr	3-Hour g/s	24-Hour lb/hr	24-Hour g/s	PSD Source (EXP/CON)	Modeled in AAQS	Modeled in Class II
	Aux Blr PSD	MARTAUX	543.1	2,992.9	60.0	18.3	3.6	1.10	504	535	50.0	15.24	102.4	12.90	102.4	12.90	CON	Yes	Yes
	Diesel Gens PSD	MARTGEN	543.1	2,992.9	25.0	7.6	1.0	0.30	955	786	130.0	39.62	4.0	0.51	4.0	0.51	CON	Yes	Yes
	Unit 8	MART8OIL	543.1	2,992.9	120.0	36.6	19.0	5.79	296	420	73.5	22.40	412.4	51.96	412.4	51.96	CON	Yes.	Yes
0850102	Indiantown Cogemation LP - Indiantown Plant PSD																		
	Polverized Coal Main Boiler	INDTOWN1	545.6	2,990.7	495.0	150.9	16.0	4.88	140	333	93.2	30.50	582.0	73.30	581.7	73.30	CON	Yes	Yes
	Auxiliary and Temporary Boilers	INDTOWN3	545.6	2,990.7	210.0	64.0	5.0	1.52	350	450	87.6	26.70	18.0	2.30	18.3	2.30	CON	Yes	Yes
0110037	FPL - Lauderdale																		
	CTs 1-4 PSD	LAUDU45	580.1	2883.3	150.0	45.7	18.0	5.49	330	439	47.9	14.60	2152.0	271.15	2152.0	271.15	CON	Yes	Yes
	4&5 PSD Baseline	FTLAU45B	580.1	2883.3	151.0	46.0	14.0	4.27	300	422	48.0	14.63	-3627.0	-457.00	-3627.0	-457.00	EXP	No	Yes
0710000	FPL Fort Myers																		
	Unit 1 PSD	FMU1	422.1	2,952.9	301.2	91.8	9.5	2.90	300	422	98.1	29.90	-4646.8	-585.50	-4646.8	-585.50	EXP	No	Yes
	Unit 2 PSD	FMU2	422.1	2,952.9	397.6	121.2	18.1	5.52	275	408	63.0	19.20	-10587.3	-1334	-10587.3	-1334.0	EXP	No	Yes
	HRSGs 1 - 6	FMYHR1_6	422.1	2,952.9	125.0	38.1	19.0	5.79	220	378	46.6	14.2	30.6	3.86	30.6	3.9	CON	Yes	Yes
0990568	Lake Worth Utilities																		
	Unit 3, S-3	LAKWTHU3	592.8	2,943.7	112.9	34.4	7.0	2.13	293	418	51.5	15.70	799.2	100.70	799.2	100.70	NO	Yes	No
	Unit 4, S-4	LAKWTHU4	592.8	2,943.7	115.2	35.1	7.5	2.29	293	418	55.8	17.00	1030.6	129.85	1030.6	129.85	NO	Yes	No
	Unit 5, S-5	LAKWTHU5	592.8	2,943.7	75.1	22.9	10.0	3.05	406	481	91.2	27.80	114.0	14.37	114.0	14.37	CON	Yes	Yes
0990042	FPL Riviera[c]																		
	Units 3&4 at 2.5%s fuel oil	RIVU34	594.2	2,960.6	297.9	90.8	16.0	4.88	263	402	62.0	18.90	16775.0	2113.65	16775.0	2113.65	NO	Yes	No
0610029	Vero Beach Power[c]																		
	Unit 1	VERBU1	567.1	3056.5	200.0	60.96	3.5	1.07	327	437	106.4	32.42	228.3	28.77	228.3	28.77	NO	Yes	No
	Unit 2	VERBU2	567.1	3056.5	200.0	60.96	3.5	1.07	322	434	123.3	37.57	668.3	84.21	668.3	84.21	NO	Yes	No
	Unit 3	VERBU3	567.1	3056.5	200.0	60.96	6.0	1.83	333	440	65.4	19.93	1127.5	142.07	1127.5	142.07	NO	Yes	No
	Unit 4	VERBU4	567.1	3056.5	200.0	60.96	7.0	2.13	306	425	79.9	24.36	548.0	69.05	548.0	69.05	NO	Yes	No
	Unit 5 Simple Cycle CT	VERBU5	567.1	3056.5	125.0	38.1	11.0	3.35	290	416	64.2	19.56	123.0	15.50	123.0	15.50	CON	Yes	Yes
0110036	FPL Port Everglades[c]																		
	Units 1&2 at 2.5%s fuel oil	PTEVU12	587.4	2885.3	342.8	104.5	14.0	4.27	289	415.9	87.7	26.7	12650	1593.9	12650	1593.9	NO	Yes	No
	Units 3&4 at 2.5%s fuel oil	PTEVU34	587.4	2885.3	342.8	104.5	18.1	5.52	287	414.8	78.3	23.9	22000	2772.0	22000	2772.0	NO	Yes	No
	GT 1-12 (0.5% fuel oil)	PTEVGTS	587.4	2885.3	44.0	13.4	15.6	4.75	860	733.2	93.3	28.4	4212	530.7	4212	530.7	NO	Yes	No

[a] Facilities or sources within facilities that operate only during the October 1 through April 30 crop season.

[b] Sugar mill sources that operate all year.

[c] Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.

TABLE 10
MAXIMUM PREDICTED SO_2 IMPACTS DUE TO THE MODELED SOURCES FOR THE AAQS SCREENING ANALYSIS

		Receptor Location				
	Concentration[a]	UTM Coordinates (m)		Local Coordinates (m)[b]		Time Period
Averaging Time	(μg/m³)	East	North	x	y	(YYMMDDHH)
Annual, Highest	7.68	505,430	2,956,850	-698	-86	01123124
	6.87	505,430	2,956,950	-698	14	02123124
	6.34	505,630	2,957,450	-498	514	03123124
	7.13	505,430	2,956,850	-698	-86	04123124
	6.10	505,430	2,956,850	-698	-86	05123124
24-Hour, HSH	33.1	505,330	2,956,750	-798	-186	01050224
	29.2	505,700	2,957,294	-428	358	02111024
	30.8	505,700	2,957,392	-428	456	03050924
	29.1	505,530	2,957,550	-598	614	04050124
	29.6	505,330	2,956,850	-798	-86	05120724
3-Hour, HSH	65.3	509,630	2,952,950	3,502	-3,986	01073021
	67.0	510,130	2,956,450	4,002	-486	02102221
	74.9	510,130	2,958,950	4,002	2,014	03051803
	62.5	505,700	2,957,392	-428	456	04052618
	66.9	503,630	2,954,450	-2,498	-2,486	05112521

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH= highest, second-highest
UTM = Universal Transverse Mercator: Zone 17, NAD27

[a] Based on the AERMOD model using 5 years of surface and upper air meteorological data from 2001 to 2005 from the NWS station at Palm Beach International Airport and Florida International University in Miami, respectively
[b] Relative to Boiler No. 4 stack location.

TABLE 11
MAXIMUM PREDICTED SO_2 IMPACTS
FOR COMPARISON TO AAQS REFINED ANALYSES

Averaging Time	Concentration (μg/m³) Total (C= A + B)	Modeled [a] (A)	Background [c] (B)	UTM Coordinates (m) East	North	Time Period (YYMMDDHH)	Florida AAQS (μg/m³)
Annual, Highest	10.7	7.68	3	505,430	2,956,850	01123124	60
24-Hour, HSH	38.1	33.1	5	505,330	2,956,750	01050224	260
3-Hour, HSH	87.9	74.9	13	510,130	2,956,450	02102221	1,300

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH= highest, second-highest
UTM = Universal Transverse Mercator: Zone 17, NAD27

[a] Based on the AERMOD model using 5 years of surface and upper air meteorological data from 2001 to 2005 from the NWS station at Palm Beach International Airport and Florida International University in Miami, respectively.
[c] Based on monitoring data (see Section 3.0); highest annual and second-highest 24-hour average concentrations.

TABLE 12
MAXIMUM PREDICTED SO_2 IMPACTS DUE TO THE MODELED SOURCES
FOR THE PSD CLASS II INCREMENT CONSUMPTION SCREENING ANALYSIS

		Receptor Location				
	Concentration[a]	UTM Coordinates (m)		Local Coordinates (m)[b]		Time Period
Averaging Time	(µg/m³)	East	North	x	y	(YYMMDDHH)
Annual, Highest	0.00	NA	NA	NA	NA	01123124
	0.00	NA	NA	NA	NA	02123124
	0.00	NA	NA	NA	NA	03123124
	0.00	NA	NA	NA	NA	04123124
	0.00	NA	NA	NA	NA	05123124
24-Hour, HSH	9.0	505,230	2,956,650	-898	-286	01050224
	7.2	505,230	2,956,650	-898	-286	02092924
	7.5	505,530	2,956,650	-598	-286	03091424
	8.4	505,330	2,956,750	-798	-186	04092124
	7.1	505,430	2,957,350	-698	414	05092124
3-Hour, HSH	16.0	505,530	2,956,950	-598	14	01072812
	38.5	510,130	2,956,950	4,002	14	02100603
	19.5	510,130	2,952,950	4,002	-3,986	03091024
	16.0	505,530	2,957,050	-598	114	04071012
	25.5	510,130	2,960,950	4,002	4,014	05120321

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH= highest, second-highest
UTM = Universal Transverse Mercator: Zone 17, NAD27
NA= not applicable. PSD increment consumption is less than 0.0 ug/m³.

[a] Based on the AERMOD model using 5 years of surface and upper air meteorological data from 2001 to 2005 from the NWS station at Palm Beach International Airport and Florida International University in Miami, respectively.
[b] Relative to Boiler No. 4 stack location.

TABLE 13
MAXIMUM PREDICTED SO_2 IMPACTS
FOR COMPARISON TO THE PSD CLASS II INCREMENT, REFINED ANALYSES

Averaging Time	Concentration[a] (µg/m³)	UTM Coordinates (m) East	UTM Coordinates (m) North	Time Period (YYMMDDHH)	PSD Class II Increment (µg/m³)
Annual, Highest	0.0	NA	NA	NA	20
24-Hour, HSH	9.0	505,230	2,956,650	01050224	91
3-Hour, HSH	38.5	510,130	2,952,950	03091024	512

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH= highest, second-highest
UTM = Universal Transverse Mercator: Zone 17, NAD27

[a] Based on the AERMOD model using 5 years of surface and upper air meteorological data from 2001 to 2005 from the NWS station at Palm Beach International Airport and Florida International University in Miami, respectively.

TABLE 14
MAXIMUM IMPACTS PREDICTED FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS AT THE EVERGLADES NATIONAL PARK

Pollutant	Averaging Time	Concentration[a] ($\mu g/m^3$) 2001	2002	2003	PSD Class I Significant Impact Level ($\mu g/m^3$)
SO_2[b]	Annual	0.002	0.003	0.003	0.1
	24-Hour High	0.067	0.080	0.063	0.2
	3-Hour High	0.209	0.191	0.306	1.0
NO_2[c]	Annual	0.002	0.002	0.003	0.1
PM_{10}[d]	Annual	0.001	0.002	0.001	0.2
	24-Hour High	0.034	0.034	0.029	0.3

[a] Based on the CALPUFF model using 3 years of 4-km CALMET domain for 2001, 2002, and 2003

[b] Based on maximum 1-hour emission rate of 71.1 lb/hr.

[c] Based on annual emission rate of 473.7 TPY.

[d] Based on maximum 24-hour emission rate of 26.93 lb/hr.

BEST AVAILABLE COPY

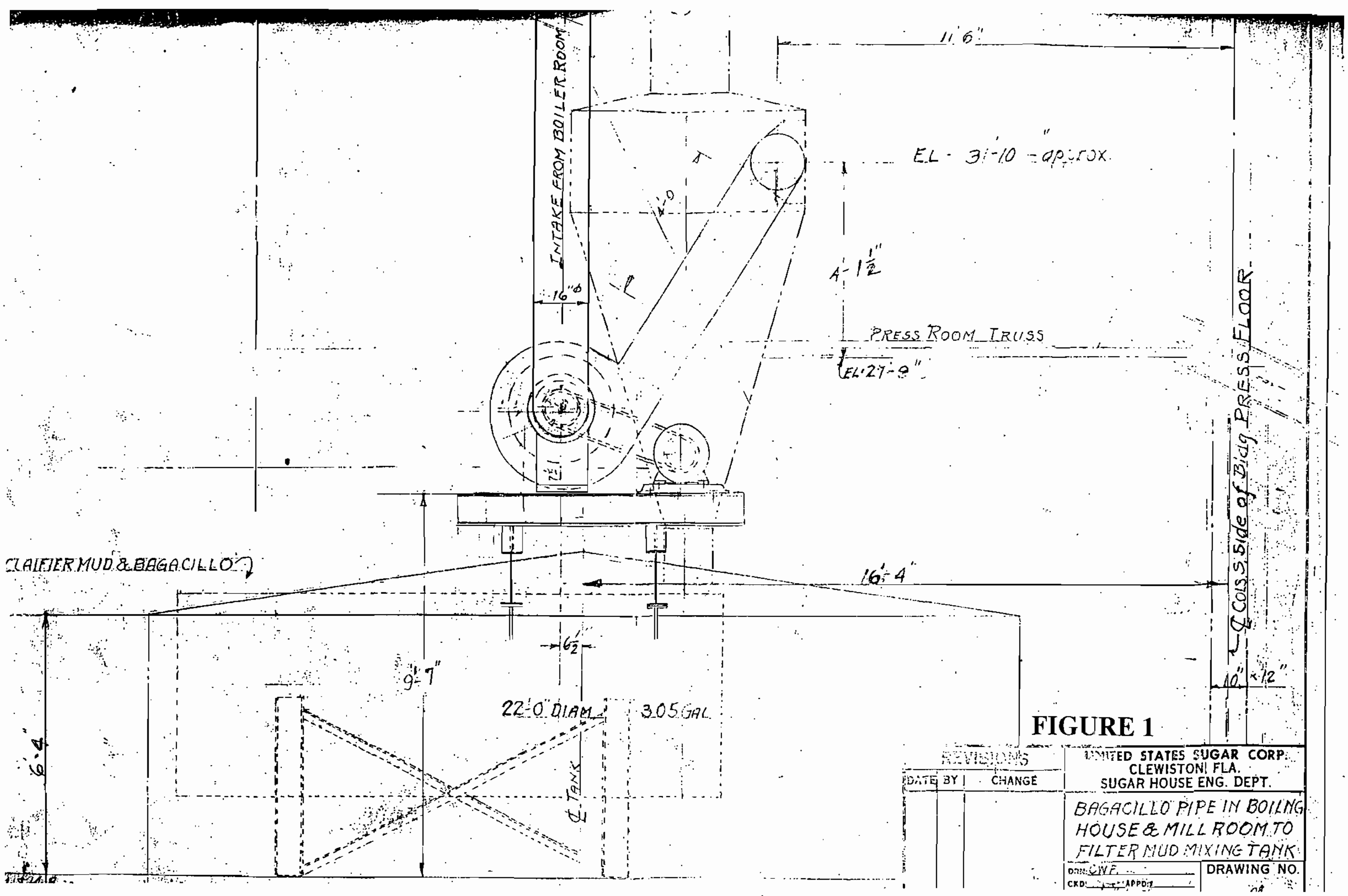
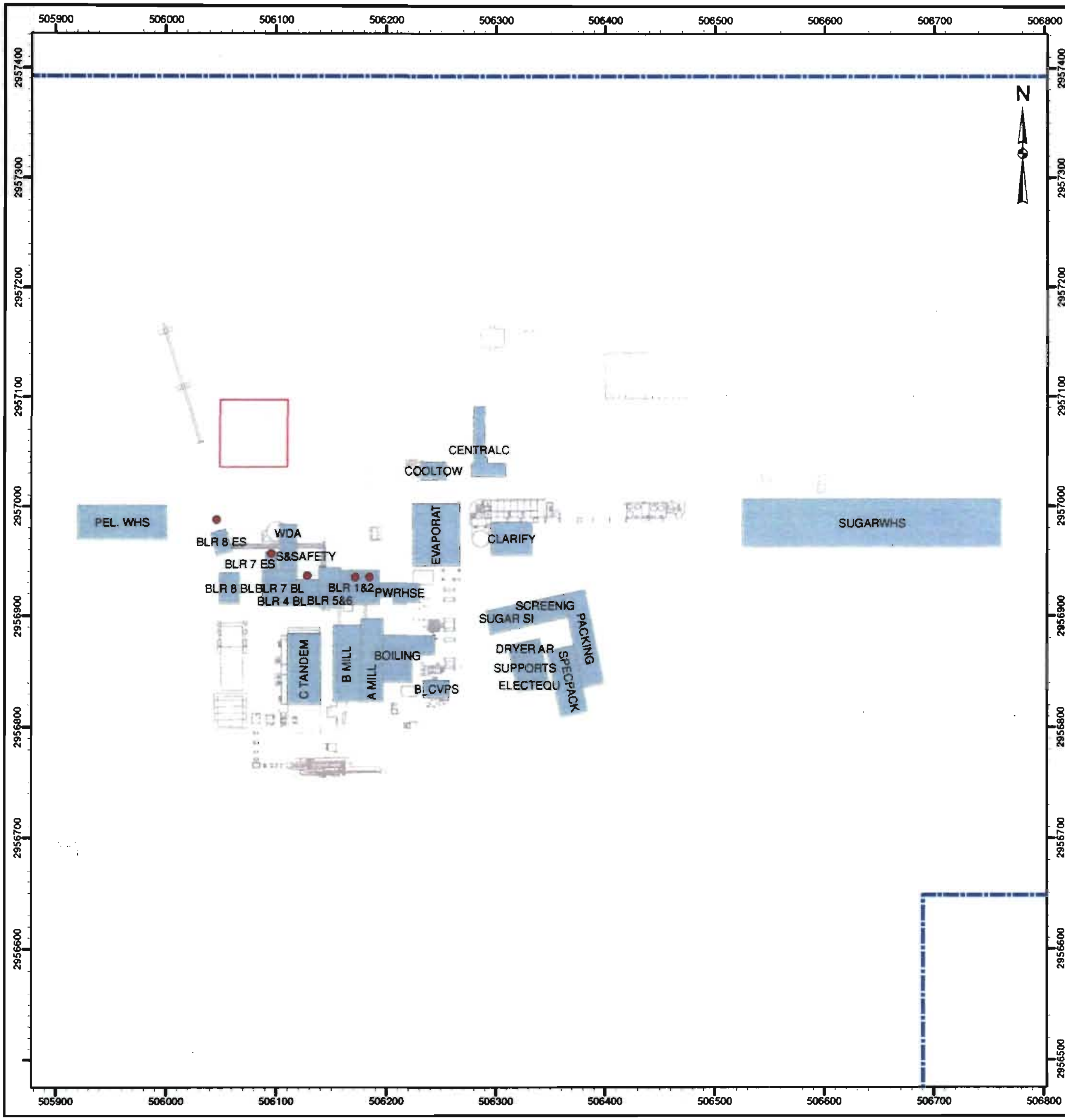


FIGURE 1



LEGEND

- Point Source
- Area Source
- Buildings Used in Downwash
- Property Boundary

PROPERTY BOUNDARY

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

100 0 100 Meters

PROJECT	U.S. Sugar Corporation Clewiston Mill
TITLE	**Source and Building Locations**

Golder Associates, Gainesville, Florida

PROJECT No			SCALE AS SHOWN	REV 0
DESIGN	AB	17 Oct 2006		
GIS	AB	17 Oct 2006		
CHECK	SM	17 Oct 2006		
REVIEW	CB	17 Oct 2006		

FIGURE 2

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

June 5, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, Vice President of Sugar Processing Operations
U.S. Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

Re: **Request for Additional Information**
Project Nos. 0510003-0031-AC and 0510003-032-AV
Clewiston Sugar Mill and Refinery / Bryant Sugar Mill
Title V Renewal Projects

Dear Raiola:

The Department is currently processing your application for a permit to renew the Title V air operation permits for the Clewiston Sugar Mill and Refinery and the Bryant Sugar Mill. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the items below require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Please review "Attachment A – Summary of CAM Plans Proposed by Applicant" of this request for accuracy. The following questions refer to this attachment and the CAM Plans.

   a. Explain why the proposed monitoring values were reduced by 90%.

   b. Explain why some of the proposed indicator ranges are so much lower than the annual averages identified in the application. (i.e., Clewiston Boilers 1, 2 and 4, and Bryant Boilers 1 and 5. etc.)

   c. Provide a technical justification for reducing the monitoring frequency from 4 times/hour for units with potential emissions greater than 100 tons per yea (i.e., units operate under relatively steady operational loads; control equipment parameters are "dialed-in" and only reset for large swings in operation; proposed monitoring frequency will be increased from current monitoring frequency; unit has shown relatively low emissions for proposed indicator range; etc.). Explain any difficulties with continuously monitoring the total secondary power input to the ESP for Clewiston Boiler 7.

   d. Clewiston Boiler 7 and 8 have wet cyclones as pre-control devices prior to the ESP. Although pressure drop was an important parameter in selecting and designing the wet cyclones, it is not a controllable parameter and is dependent on boiler load/flue gas exhaust rate. However, the water flow rate to the wet cyclones is a controllable parameter and monitoring for a minimum flow rate will ensure proper operation. Please identify the minimum operational flow rate (CAM indicator range) for these devices.

   e. Although Boiler 8 is subject to a NESHAP promulgated after 11/15/90, it is necessary to establish a CAM Plan for the PM BACT standard. However, these monitoring requirements can be the same because the emissions standards and averaging period are identical. Please comment.

   f. As was previously discussed, the Department identified Clewiston Boilers 4, 7 and 8 as possibly being subject to CAM Plan requirements for SO_2 emissions because these units have a specific SO_2 emissions standard. Also as discussed, the Department reviewed SO_2 emissions data and control options for the Clewiston Boilers (some wet controls) and the Okeelanta Cogeneration Boilers (dry controls). Based on our conversation and available information, the following is a summary of this review:

   "For the Clewiston Mill, bagasse typically contains 0.08% to 0.24% with an average of approximately 0.1% sulfur by weight on a dry basis. Based on a heating value of 7200 Btu per dry lb of bagasse, this is equivalent to

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. William A. Raiola, V.P. of Sugar
Processing Operations
Clewiston Sugar Mill and Refinery
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☐ Addressee

B. Received by (Printed Name)
C. Date of Delivery 6-8-6

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 1533

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

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7000 1670 0013 3110 1533

S
S
C

Mr. William A. Raiola, V.P. of Sugar
Processing Operations
Clewiston Sugar Mill and Refinery
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, Florida 33440

PS Form 3800, May 2000 See Reverse for Instructions estimated uncontrolled emissions of approximately 0.22 to 0.66 lb SO_2 per MMBtu. However, stack test data for these units show actual SO_2 emissions ranging from 0.01 to 0.06 lb/MMBtu. This represents estimated reductions ranging from 40% to 90%.

The sugar industry typically uses surface water from ponds for wet scrubber and wet cyclone water. The applicant indicates that the typical pH of the pond water is 6.8. No chemicals are added to treat and control the pH levels of the scrubber water, which is used and then discharged back into the pond. According to the industry, the mechanism providing the reduction is adsorption of the SO_2 onto ash particles generated from bagasse combustion, which is then removed by the particulate matter control device.

To evaluate this mechanism, data from the Okeelanta Cogeneration Boilers were reviewed. These units are spreader-stoker boilers similar in size to the Clewiston Boilers (760 MMBtu per hour) and fire roughly a 50%-50% blend of bagasse and wood chips as the primary fuel. However, water is not used in the particulate control device. Instead, particulate matter is removed with dry multi-clones followed by a dry electrostatic precipitator (ESP). For the Okeelanta Mill, the important parameters are:

- Bagasse: 3600 Btu/lb, wet; 50% moisture; and an average sulfur content of 0.03% by weight
- Wood Chips: .4500 Btu/lb, wet; 40% moisture; and an average sulfur content of 0.07% by weight

Assuming a 50%-50% biomass blend by weight provides a fuel blend with an average heating value of 7350 MMBtu/lb and an average sulfur content of 0.05% sulfur by weight. This is equivalent to an uncontrolled emission rate of approximately 0.135 lb SO_2 per MMBtu. However, the cogeneration boilers are equipped with monitors to continuously measure and record SO_2 emissions. Based on CEMS data collected in 2000 for the cogeneration boilers, the average annual SO_2 emission rate for these units was approximately 0.03 lb/MMBtu. This represents an estimated reduction of approximately 78%, which tends to validate that the SO_2 removal mechanism as adsorption onto ash particles with removal by the particulate matter control device.

This information supports the contention that SO_2 emissions are not being removed as a result of the "wet" scrubbing process. Nevertheless, the conclusion is that a properly functioning particulate matter control device is necessary to achieve the SO_2 emission standards. Therefore, the Department intends to establish the same CAM monitoring program as identified for particulate matter for Clewiston Boilers 4, 7 and 8."

Please correct any inaccuracies and comment.

g. For the granular carbon regenerative furnace (GCRF), Permit No. PSD-FL-272 specified a particulate matter emission standard of 0.7 lb/hour and a design control efficiency of 97%. Based on these parameters, the uncontrolled emission rate would be 102 tons/year. The permit specifies that the venturi scrubber shall be designed for a pressure drop of between 20 to 30 inches of water column and the wet tray scrubber shall be designed for a pressure drop of between 3 to 5 inches of water column. The permit requires these parameters to be monitored once per 8-hour shift. Please provide a CAM Plan for this control device. What is the "capacity" of this unit?

2. Based on the revisions to NSPS Subpart Kb, do you want to consolidate all fuel storage tanks into a single emissions unit to simplify reporting for the Annual Operating Report? If so, please identify the tanks, identification numbers, storage volume, and materials stored.
3. White Sugar Dryer 2 (EU-029) has not yet conducted a satisfactory compliance test. Do you want to include this unit in the Title V renewal or proceed without it? If included, please submit a compliance plan for conducting the test and submitting the test report. (Once satisfied, the requirements of the compliance plan will become obsolete.)
4. The PSD permit for Boiler 8 was recently modified (Project 0510003-032-AC) and updated for the NESHAP revisions. Please submit only the revised Title application pages for this unit.
5. The Department's South District Office issued Permit No. 0510003-033-AC to install a new lime silo. If constructed, please submit the revised Title V application pages for this new unit. If not yet constructed, you may submit the revised Title V application pages for this new unit with a compliance plan. For minor units such as this, the compliance plan would likely cover any notification and initial testing requirements. (Once satisfied, the requirements of the compliance plan will become obsolete.)
6. The Bureau of Air Regulation recently issued Permit No. 0510003-034-AC to install the railcar loading/unloading/storage system at the refinery. You may submit the revised Title V application pages for this new

unit with a compliance plan. The permit requires only an opacity test and the submittal of the test report. (Once satisfied, the requirements of the compliance plan will become obsolete.)

7. The Bureau of Air Regulation recently issued Draft Permit No. 0510003-035-AC to install a dry cyclone dust collector for Boiler 8. The only requirement is a notification of completion of construction, which would be listed as the compliance plan and become obsolete once submitted. Please submit only the revised application pages for the proposed dry cyclone dust collector for Boiler 8.

8. You have recently submitted a request to EPA Region 4 to remove the NESAHP requirement to monitor pressure drop across the wet cyclones. Do you want to include this request as part of the Title V renewal project or proceed without these revisions?

9. On May 19, 2006, we received your request to revise the original permit that modified the oil firing systems for Boilers 1 and 2. The Department intends to issue a revised permit shortly based on your request. The revision must be included in the Title V renewal project because all construction and testing is now complete. Please submit only the revised Title V application pages for these units.

10. You had previously indicated you would request a revision of the bagasse handling system regarding the installation of dust collectors as well as a revision to increase the maximum steam production rate for Boiler 8. Do you plan to submit this request shortly and include it as part of the Title V renewal project or proceed without these revisions?

11. Please review the previously submitted compliance plan and update as necessary.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
BAR - Air Permitting North

cc: Mr. Don Griffin, U.S. Sugar Corporation
Mr. David Buff, P.E., Golder Associates
Mr. Ron Blackburn, SD Office
Mr. James Stormer, PBCHD
Ms. Kathleen Forney, EPA Region 4

Wet Impingement Scrubbers

Clewiston Boiler 1 (EU-001)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	6 inches water column, minimum **Average: 9" w.c.**	50 gpm, minimum **Average: 300 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Recorded once per 8-hour shift **Current: Every 8 hours**

Clewiston Boiler 2 (EU-002)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	5 inches water column, minimum **Average: 9" w.c.**	58 gpm, minimum **Average: 300 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Recorded once per 8-hour shift **Current: Every 8 hours**

Clewiston Boiler 4 (EU-009)	Indicator #1	Indicator #2
Indicator (PM and SO_2)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	7.6 inches w. c., minimum **Average: 8" w.c.**	220 gpm, minimum **Average: 375 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 3 hours**	Recorded once per 8-hour shift **Current: Every 3 hours**

Bryant Boiler 1 (EU-001)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	4.5 inches w.c., minimum **Average: 8.8" w.c.**	200 gpm, minimum **Average: 240 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Recorded once per 8-hour shift **Current: Every 8 hours**

Bryant Boiler 2 (EU-002)	Indicator #1	Indicator #2
Indicator (PM) per Scrubber (2 Scrubbers)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	3.6 inches w.c., minimum **Average: 4.8" w.c.**	200 gpm, minimum **Average: 170 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Recorded once per 8-hour shift **Current: Every 8 hours**

Bryant Boiler 3 (EU-003)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	5.4 inches w.c., minimum **Average: 7.2" w.c.**	216 gpm, minimum **Average: 240 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Recorded once per 8-hour shift **Current: Every 8 hours**

Bryant Boiler 5 (EU-005)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	7.2 inches w.c., minimum **Average: 11.5" w.c.**	765 gpm, minimum **Average: 400 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Recorded once per 8-hour shift **Current: Every 8 hours**

Wet Cyclones - Pre-Controls

Clewiston Boiler 7 (EU-014)	Indicator #1
Indicator (PM and SO_2)	Total scrubber water flow rate
Measurement Approach	Flow Meter
Indicator Range	??? gpm, minimum **Average: 40 gpm**
Monitoring Frequency	Continuous readout
Data Collection	**Current: Not recorded**

Clewiston Boiler 8 (EU-028)	Indicator #2
Indicator (PM and SO_2)	Total scrubber water flow rate
Measurement Approach	Flow Meter
Indicator Range	??? gpm, minimum **Average: 713 gpm**
Monitoring Frequency	Continuous readout
Data Collection	**Current: Not recorded**

Electrostatic Precipitator – Primary Controls

Clewiston Boiler 7 (EU-014)	Indicator #1
Indicator (PM)	Total Secondary Power Input
Measurement Approach	Amp/Volt Meter
Indicator Range	44 kW, minimum **Average:**
Monitoring Frequency	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**

Clewiston Boiler 8 (EU-028)	Indicator #1
Indicator (PM)	Total Secondary Power Input
Monitoring Approach	Identical to NEHSAP Subpart DDDDD requirements

Venturi Scrubber

Clewiston GCRF (EU-017)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	??? inches w.c., minimum **Design: 20"-30" w.c.**	??? gpm, minimum **Design: 36 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	Not recorded **Current: Not recorded**

Tray Scrubber

Clewiston GCRF (EU-017)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	??? inches w.c., minimum **Design: 3" - 5" w.c.**	??? gpm, minimum **Design: 230 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per 8-hour shift **Current: Every 8 hours**	??? **Current: Not recorded**

Baghouse

Clewiston 3 Vacuum Pickups (EU-018)	Indicator #1	Indicator #2
Indicator (PM) per Baghouse – 3 Units	Pressure drop across baghouse	Opacity
Measurement Approach	Manometer (or equivalent)	EPA Method 22
Indicator Range	?? inches water column, minimum **Average: ???**	Observed visible emissions
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Recorded once per day **Current: No recording**	Recorded once per day **Current: No recording**

Wet Vortex Scrubber

Clewiston White Sugar Dryer 2 (EU-029)	Indicator #1	Indicator #2
Indicator (PM)	Pressure drop across scrubber	Total scrubber water flow rate
Measurement Approach	Manometer (or equivalent)	Flow Meter
Indicator Range	Under construction **Design: 8" w.c.**	Under construction **Design: 12 gpm**
Monitoring Frequency	Continuous readout	Continuous readout
Data Collection	Continuously, 3-hr block avg.	Continuously, 3-hr block avg.

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL USA 32653
Telephone (352) 336-5600
Fax (352) 336-6603
www.golder.com

Golder Associates

RECEIVED 063-7563
JUN 07 2006
BUREAU OF AIR REGULATION

June 5, 2006

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. Jeff Koerner, Air Permitting South

RE: UNITED STATES SUGAR CORPORATION, CLEWISTON MILL
BOILER NO. 8 PERMIT REVISION APPLICATION
PERMIT NO. 0510003-030-AC

Dear Mr. Jeff Koerner:

Please find enclosed four copies of the permit revision application for the Clewiston Mill Boiler No. 8. This application is to incorporate a higher steaming rate and a longer boiler startup time for Boiler No. 8, and to revise the controls utilized on the bagasse handling and conveying system. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

Enclosures

0510003-037-AC

DB/CB/all

cc: Ron Blackburn, FDEP South District
Don Griffin
Peter Briggs

Y:\Projects\2006\0637563 USSC Boilers 1 & 2 and Boiler 8\Boiler #8\4.1\L060506.doc

BOILER NO. 8
PERMIT REVISION
U.S. SUGAR CORPORATION
CLEWISTON, FLORIDA

Prepared For:
United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, Florida 33440

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

June 2006
063-7563

DISTRIBUTION:
5 Copies – FDEP
2 Copies – U.S. Sugar Corporation
2 Copies – Golder Associates Inc.

PERMIT APPLICATION LONG FORM

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **United States Sugar Corporation**	
2. Site Name: **U.S. Sugar Clewiston Mill**	
3. Facility Identification Number: **0510003**	
4. Facility Location...: Street Address or Other Locator: **W.C. Owens Ave. and S.R. 832** City: **Clewiston** County: **Hendry** Zip Code: **33440**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Neil Smith, Vice President and General Manager, Sugar Processing Operations**
2. Application Contact Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce de Leon Avenue** City: **Clewiston** State: **FL** Zip Code: **33440**
3. Application Contact Telephone Numbers... Telephone: **(863) 902-2703** ext. Fax: **(863) 902-2729**
4. Application Contact Email Address: **nsmith@ussugar.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 6-7-06	3. PSD Number (if applicable):
2. Project Number(s): 0510003-037-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Revision to Boiler No. 8 permit (Permit No. PSD-FL-333B/0510003-030-AC) to incorporate a higher steaming rate and a longer boiler startup time (8-12 hours), and to revise the controls utilized on the bagasse handling and conveying system.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
028	Boiler No. 8		
027	Biomass Handling System		

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Neil Smith, Vice President and General Manager, Sugar Processing Operations**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **United States Sugar Corporation** Street Address: **111 Ponce de Leon Avenue** City: **Clewiston** State: **FL** Zip Code: **33440**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 902-2703** ext. Fax: **(863) 902-2729**
4.	Owner/Authorized Representative Email Address: **nsmith@ussugar.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Signature: [signature] Date: 6/2/06

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:
   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff
Signature

6/5/06
Date

(Seal)

PROFESSIONAL ENGINEER DAVID A. BUFF No. 19011 STATE OF FLORIDA

* Attach any exception to certification statement.
** **Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 506.1 North (km) 2956.9		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 26/44/06 Longitude (DD/MM/SS) 80/56/19	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 20	6. Facility SIC(s): 2061 2062
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Neil Smith, Vice President and General Manager, Sugar Processing Operations
2. Facility Contact Mailing Address... Organization/Firm: United States Sugar Corporation Street Address: 111 Ponce de Leon Avenue City: Clewiston State: FL Zip Code: 33440
3. Facility Contact Telephone Numbers: Telephone: (863) 902-2703 ext. Fax: (863) 902-2729
4. Facility Contact Email Address: nsmith@ussugar.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **One or more emission units is potentially subject to NESHAP for asbestos removal in the event that the facility may wish to perform asbestos removal in the future. Boiler No. 8 is also subject to 40 CFR 63, Subpart DDDDD.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total – PM	A	N
Sulfur Dioxide – SO_2	A	N
Nitrogen Oxides – NO_x	A	N
Carbon Monoxide – CO	A	N
Particulate Matter – PM_{10}	A	N
Sulfuric Acid Mist – SAM	A	N
Total Hazardous Air Pollutants – HAPs	A	N
Volatile Organic Compounds – VOCs	A	N
Acetaldehyde – H001	A	N
Benzene – H017	A	N
Formaldehyde – H095	A	N
Hydrogen Chloride – H106	A	N
Mercury – H114	B	N
Phenol – H144	A	N
Polycyclic Organic Matter – H151	A	N
Styrene – H163	A	N
Toluene – H169	A	N
Naphthalene – H132	A	N
Dibenzofuran – H058	A	N
Ammonia – NH_3	B	N

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:____ ☒ Previously Submitted, Date: **February 2005**
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date: **February 2005**
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Attachment A** ☐ Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:_____ ☒ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **Attachment A**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Attachment A**
4.	List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☒ Attached, Document ID: **Attachment A** ☐ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☐ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:_____ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:_____ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:_____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:_____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:_____ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:_____ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: **Boiler No. 8**

3. Emissions Unit Identification Number: **028**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**Nov. 2003**	**March 2005**	**20**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

    Stoker boiler fired by carbonaceous fuel and low sulfur No. 2 fuel oil.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Electrostatic Precipitator** **Wet Sand Separator** **Selective Non-Catalytic Reduction System (SNCR)** **Dry Cyclone**	
2. Control Device or Method Code(s): **010, 099, 107, 075**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **633,000 lb/hr**	
3. Maximum Heat Input Rate: **1,185** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on 1-hour maximum steam rate (above) for carbonaceous fuel firing. Maximum 24-hour average firing for carbonaceous fuel is 1,077 MMBtu/hr, based on a 24-hour steam rate of 575,000 lb/hr. Maximum for No. 2 fuel oil is 562 MMBtu/hr. Maximum annual heat input limited to 6,767,100 MMBtu/yr.** **See Attachments USSC-EU1-B6a and USSC-EU1-B6b.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **BLR-8**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **13.0** feet
8. Exit Temperature: **315** °F	9. Actual Volumetric Flow Rate: **395,000** acfm	10. Water Vapor: **24** %
11. Maximum Dry Standard Flow Rate: **270,000** dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack parameters are based on biomass firing at the maximum 24-hour heat input rate. Maximum standard flow rates are at 7-percent oxygen.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **External combustion boilers; industrial; bagasse; all boiler sizes**		
2. Source Classification Code (SCC): **1-02-011-01**		3. SCC Units: **Tons Burned**
4. Maximum Hourly Rate: **164.58**	5. Maximum Annual Rate: **939,875**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.1 (dry)**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Maximum hourly rate based on bagasse firing at 1,185 MMBtu/hr (1-hour max) and maximum annual rate based on 6,767,100 MMBtu/yr. See Attachment USSC-EU1-B6b.**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **External combustion boilers; industrial; distillate oil; grades 1 and 2**		
2. Source Classification Code (SCC): **1-02-005-01**		3. SCC Units: **1000 Gallons**
4. Maximum Hourly Rate: **4.161**	5. Maximum Annual Rate: **6,073.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **135**
10. Segment Comment: **Maximum rates based on fuel oil firing at 562 MMBtu/hr and a maximum of 6,073,600 gallons of fuel oil per year.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): **External combustion boilers; industrial; wood/bark (>50,000 lb/hr steam)**		
2. Source Classification Code (SCC): **1-02-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **131.67**	5. Maximum Annual Rate: **831,339**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05 (dry)**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **8.14**
10. Segment Comment: **Maximum hourly rate based on 1,185 MMBtu/hr (1-hour max) and 4,070 Btu/lb (wet) for wood/bark. Maximum annual rate based on 6,767,100 MMBtu/yr.**		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	099	010	EL
PM_{10}	099	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
SAM			NS
PB	099	010	NS
H017 (Benzene)			NS
H095 (Formaldehyde)			NS
H106 (Hydrogen Chloride)	010		EL
H114 (Mercury)			EL
HAPs			NS
NH_3 (Ammonia)			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **29.63** lb/hour **84.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **MACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 0.025 lb/MMBtu = 29.63 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 0.025 lb/MMBtu = 26.93 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 0.025 lb/MMBtu ÷ 2,000 lb/ton = 84.6 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B and 40 CFR 63, Subpart DDDDD, Table 1.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **29.63** lb/hour **84.6** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT Limit, 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **29.63** lb/hour **84.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Maximum 1-hour rate: 1,185 MMBtu/hr x 0.025 lb/MMBtu = 29.63 lb/hr** **Maximum 24-hour rate: 1,077 MMBtu/hr x 0.025 lb/MMBtu = 26.93 lb/hr** **Maximum annual rate: 6,767,100 MMBtu/yr x 0.025 lb/MMBtu ÷ 2,000 lb/ton = 84.6 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.025 lb/MMBtu**	4. Equivalent Allowable Emissions: **29.63** lb/hour **84.6** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT Limit. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.1** lb/hour **203.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 0.06 lb/MMBtu = 71.1 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 0.06 lb/MMBtu = 64.62 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 0.06 lb/MMBtu ÷ 2,000 lb/ton = 203.0 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu**	4. Equivalent Allowable Emissions: **71.1** lb/hour **203.0** tons/year
5. Method of Compliance: **EPA Method 6C**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **28.1** lb/hour **20.5** tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Emissions representative of No. 2 fuel oil firing with 0.05 percent sulfur. Annual emissions based on proposed limit of 6,073,600 gal/yr.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **355.5** lb/hour **473.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.14 lb/MMBtu, 30-day rolling average** Reference: **Permit No. 0510003-030-AC/PSD-FL-333B**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 0.30 lb/MMBtu = 355.5 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 0.30 lb/MMBtu = 323.1 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 473.7 TPY

11. Potential Fugitive and Actual Emissions Comment:

Maximum 1-hour and 24-hour rates represent worst-case uncontrolled emissions without the SNCR system. Annual average is 30-day rolling average limit, based on Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.14 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **473.7** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT limit based on 30-day rolling average.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7,702.5** lb/hour **1,285** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **400 ppmvd @ 7% O_2, 30-day rolling average** Reference: **MACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 6.5 lb/MMBtu = 7,702.5 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 6.5 lb/MMBtu = 7,000.5 lb/hr

30-day rolling average based on 40 CFR 63, Subpart DDDDD:
400 ppmvd @ 7% O_2 x 270,000 dscfm @ 7% O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1,545.6/28) ft-lb_f/lb_m-°R ÷ 528°R = 470.6 lb/hr

Annual based on 30-day rolling average:
470.6 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 2,061.2 TPY

11. Potential Fugitive and Actual Emissions Comment:

Annual limit based on 12-month rolling total from Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **400 ppmvd @ 7% O_2**	4. Equivalent Allowable Emissions: **470.6** lb/hour **2,061.2** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **MACT Limit, 40 CFR 63, Subpart DDDDD, Table 1. Limit based on 30-day rolling average.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1,285 TPY**	4. Equivalent Allowable Emissions: lb/hour **1,285** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit based on 12-month rolling total. Annual TPY includes periods of startup, shutdown, and malfunction (SSM).**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **59.25** lb/hour **169.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.05 lb/MMBtu** Reference: **BACT Limit**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 0.05 lb/MMBtu = 59.25 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 0.05 lb/MMBtu = 53.85 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 0.05 lb/MMBtu ÷ 2,000 lb/ton = 169.2 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing. Based on Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **59.25** lb/hour **169.2** tons/year
5. Method of Compliance: **EPA Methods 18 and 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT Limit. Emissions representative of bagasse firing only.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.38** lb/hour **12.52** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0037 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **4**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 0.0037 lb/MMBtu = 4.38 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 0.0037 lb/MMBtu = 3.98 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 0.0037 lb/MMBtu ÷ 2,000 lb/ton = 12.52 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing. Factor based on the SO_2 emission factor and a 5% conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.018** lb/hour **0.052** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.55×10^{-5} lb/MMBtu** Reference: **Bagasse analysis and 50-percent removal**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Bagasse analysis: 3.09×10^{-5} lb/MMBtu x 0.50 = 1.55×10^{-5} lb/MMBtu

Maximum 1-hour rate: 1,185 MMBtu/hr x 1.55×10^{-5} lb/MMBtu = 0.018 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 1.55×10^{-5} lb/MMBtu = 0.017 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 1.55×10^{-5} lb/MMBtu ÷ 2,000 lb/ton = 0.052 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing. Based on bagasse analysis and assuming 50 percent removal in wet scrubber/ESP, based on stack testing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **H114 (Mercury)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0036** lb/hour **0.0102** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **$3x10^{-6}$ lb/MMBtu** Reference: **40 CFR 63, Subpart DDDDD, Table 1**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x $3x10^{-6}$ lb/MMBtu = 0.0036 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x $3x10^{-6}$ lb/MMBtu = 0.0032 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x $3x10^{-6}$ lb/MMBtu ÷ 2,000 lb/ton = 0.0102 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3×10^{-6} lb/MMBtu**	4. Equivalent Allowable Emissions: **0.0036** lb/hour **0.0102** tons/year
5. Method of Compliance: **Bagasse analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Fluorides**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.711** lb/hour **2.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **$6x10^{-4}$ lb/MMBtu** Reference: **Stack test data from similar boiler**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x $6x10^{-4}$ lb/MMBtu = 0.711 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x $6x10^{-4}$ lb/MMBtu = 0.646 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x $6x10^{-4}$ lb/MMBtu ÷ 2,000 lb/ton = 2.03 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **HCl**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **23.7** lb/hour **67.67** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.02 lb/MMBtu** Reference: **40 CFR 63, Subpart DDDDD, Table 1**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Maximum 1-hour rate: 1,185 MMBtu/hr x 0.02 lb/MMBtu = 23.7 lb/hr
Maximum 24-hour rate: 1,077 MMBtu/hr x 0.02 lb/MMBtu = 21.54 lb/hr
Maximum annual rate: 6,767,100 MMBtu/yr x 0.02 lb/MMBtu ÷ 2,000 lb/ton = 67.67 TPY

11. Potential Fugitive and Actual Emissions Comment:

Potential emissions representative of bagasse firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.02 lb/MMBtu**	4. Equivalent Allowable Emissions: **23.7** lb/hour **67.67** tons/year
5. Method of Compliance: **Annual stack testing using EPA Method 26A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 63, Subpart DDDDD, Table 1.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NH_3**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **14.3** lb/hour **62.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **20 ppmvd @ 7% O_2** Reference: **Permit No. 15003-030-AC/PSD-FL-333B**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

20 ppmvd @ 7% O_2 x 270,000 dscfm @ 7% O_2 x 60 min/hr x 2,116.8 lb_f/ft^2 ÷ (1,545.6/17) ft-lb_f/lb_m-°R ÷ 528°R = 14.3 lb/hr

14.3 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 62.6 TPY

11. Potential Fugitive and Actual Emissions Comment:

Based on Permit No. 0510003-030-AC/PSD-FL-333B.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd @ 7% O_2**	4. Equivalent Allowable Emissions: **14.3** lb/hour **62.6** tons/year
5. Method of Compliance: **Annual stack test by method EPA CTM-027.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on Permit No. 0510003-030-AC/PSD-FL-333B.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(5), F.A.C., BACT and NSPS Subpart Db.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Based on 40 CFR 63, Subpart DDDDD and Permit No. 0510003-030-AC/PSD-FL-333B.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Based on BACT and Permit No. 0510003-030-AC/PSD-FL-333B.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date **February 2005**

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USSC-EU1-I2** ☐ Previously Submitted, Date

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date **February 2005**

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **USSC-EU1-I4** ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **Attachment A** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

EMISSIONS UNIT INFORMATION
Section [1]
Boiler No. 8

Additional Requirements Comment

ATTACHMENT USSC-EU1-B6a

BOILER LOAD DATA

ATTACHMENT USSC-EU1-B6a

BOILER LOAD DATA

1. Boiler No. 8 – Annual Steam Production Basis:

Based on 75 percent capacity factor for originally permitted 1-hour steam rate of 550,000 lb/hr.

550,000 lb/hr steam x 8,760 hr/yr x 0.75 = 3.6135 x 10^9 lb steam per year

2. Steam Enthalpy Calculation

A. Steam conditions: 600 psig, 750°F
= 615 psia, 750°F
Enthalpy = 1,379 Btu/lb

B. Feedwater condition: 800 psig, 250°F
= 815 psia, 250°F
Enthalpy = 218 Btu/lb

C. Net Enthalpy: 1,379 – 218 = 1,161 Btu/lb steam

3. Heat Input Calculation (based on 62 percent thermal efficiency)

A. Maximum 1-hour:
633,000 lb/hr steam x 1,161 Btu/lb ÷ 0.62 = 1,185 MMBtu/hr

B. Maximum 24-hour:
575,000 lb/hr steam x 1,161 Btu/lb ÷ 0.62 = 1,077 MMBtu/hr

C. Annual rate:
3.6135 x 10^9 lb steam/yr x 1,161 Btu/lb ÷ 0.62 = 6,767,100 MMBtu/yr

4. Furnace Data

Furnace Type = Membrane Wall
Furnace Volume = 50,520 ft^3
Heat Release Rate (Bagasse) = 1,185 MMBtu/hr ÷ 50,520 ft^3 = 23,456 Btu/ft^3-hr
Heat Release Rate (No. 2 Fuel Oil) = 562 MMBtu/hr ÷ 50,520 ft^3 = 11,124 Btu/ft^3-hr

ATTACHMENT USSC-EU1-B6b

HEAT INPUT RATES AND MAXIMUM FUEL USAGE

ATTACHMENT USSC-EU1-B6b
BOILER NO. 8 MAXIMUM FUEL USAGE AND HEAT INPUT RATES, U.S. SUGAR CLEWISTON

Fuel	Heat Input	Heat Transfer Efficiency (%)	Fuel Firing Rate	
	Maximum Short-Term			
	(MMBtu/hr)			
Bagasse (1-hour max) [a]	1,185	62	329,167	lb/hr
Bagasse (24-hour max) [b]	1,077	62	299,167	lb/hr
Wood Chips (1-hour max) [a]	1,185	62	291,155	lb/hr
Wood Chips (24-hour max) [b]	1,077	62	264,619	lb/hr
No. 2 Fuel Oil [c]	562	62	4,161	gal/hr
	Annual Average			
	(MMBtu/yr)			
NORMAL OPERATION (100% BAGASSE)				
Bagasse	6,767,100	62	939,875	TPY
Wood Chips	0	62	0	TPY
No. 2 Fuel Oil	0	62	0	gal/yr
TOTAL	6,767,100			
100% WOOD CHIPS				
Bagasse	0	62	0	TPY
Wood Chips	6,767,100	62	831,339	TPY
No. 2 Fuel Oil	0	62	0	gal/yr
TOTAL	6,767,100			
10% FUEL OIL FIRING[d]				
Biomass	5,823,648	62	808,840	TPY
No. 2 Fuel Oil	943,452	62	6,073,600	gal/yr
TOTAL	6,767,100			

[a] Based on 633,000 lb/hr steam and 1,161 Btu/lb net enthalpy.

[b] Based on 575,000 lb/hr steam and 1,161 Btu/lb net enthalpy.

[c] Based on 300,000 lb/hr steam and 1,161 Btu/lb net enthalpy.

[d] Less than 10 percent of potential annual heat input to boiler, based on boiler design capacity (24-hr).

Notes:

Annual heat input based on 75% capacity factor (3.6135E+09 lbs steam/yr).

Fuels may be burned in combination, not to exceed total heat input.

Based on fuel heating values as follows:

- Bagasse - 3,600 Btu/lb
- Wood chips - 4,070 Btu/lb
- No. 2 Fuel Oil - 135,000 Btu/gal

ATTACHMENT USSC-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT USSC-EU1-I2

BOILER NO. 8 FUEL ANALYSIS

Parameter	Carbonaceous Fuel [a]		No. 2 Fuel Oil
	Bagasse	Wood Chips	(0.05% S max)
Density (lb/gal)	--	--	6.83
Approximate Heating Value (Btu/l	3,600 [b]	4,070 [b]	19,910
Approximate Heating Value (Btu/;	--	--	135,000
Ultimate Analysis (dry basis):			
Carbon	47.6%	40.70%	84.7%
Hydrogen	6.0%	4.90%	15.3%
Nitrogen	0.38%	0.37%	0.015%
Oxygen	42.1%	33.20%	0.38%
Sulfur	0.03% - 0.07%	0.05%	0.05%
Ash/Inorganic	2.6% - 5.3%	20.80%	0.06% [c]
Moisture	49% - 55%	38.50%	0.51% [c]

Represents typical values.

[a] Source: U.S. Sugar fuel analysis averages.
[b] Wet basis.
[c] Source: Perry's Chemical Engineer's Handbook. Sixth Edition, 1984. Represents average fuel characteristics.

ATTACHMENT USSC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT USSC-EU1-I4
CLEWISTON BOILER NO. 8

PROCEDURES FOR STARTUP AND SHUTDOWN

Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions will be taken to minimize the magnitude and duration of excess emissions during startup and shutdown of Boiler No. 8. Boiler room foreman and operating personnel will receive proper training on emissions control procedures.

Cold Startup (approximately 8 to 12 hours)

1. Turn on wet cyclone.
2. Feed clean wood into boiler combustion chamber.
3. Start fire in combustion chamber using a propane torch designed for that purpose, or light a fuel oil or natural gas burner at the lowest rate.
4. Observe the stack plume and adjust if necessary, by adjusting fuel, atomizing air, and combustion air to obtain proper combustion.
5. Feed carbonaceous fuel from the mill to the boiler slowly.
6. Energize electrostatic precipitator (ESP).
7. Activate SNCR system.
8. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fossil fuel until burners can be turned off.
9. Continue to observe the stack plume, the cyclone water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, cyclone and ESP to maintain optimum operating conditions.
10. Normally, a cold startup will require 8 to 12 hours from the first fire to normal working pressure.

Hot Startup (approximately 1 to 5 hours)

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on wet cyclone
3. Check the boiler and cyclone water levels, and make sure they are functioning properly.

4. Light a fossil fuel burner, continue to observe the stack plume, cyclone water levels, and burners.
5. Feed carbonaceous fuel from the mill to the boiler slowly at first.
6. Energize ESP.
7. Activate SNCR system.
8. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fossil fuel until burners can be turned off. As the carbonaceous fuel fire gets hot enough to meet steam demand, reduce the fossil fuel supply until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
9. Continue to observe the stack plume, cyclone water level, and carbonaceous fuel level, making adjustments to drafts, fuel, cyclone and ESP to maintain optimum operating conditions.
10. Normally, a warm startup requires 1 to 5 hours, depending on boiler operating conditions.

Shutdown

1. Stop fuel flow to the boiler, reduce forced draft, distributor air, overfire air, and induced draft.
2. Continue to observe the stack plume and cyclone water levels and make adjustments to maintain safe and optimum operating conditions.
3. After fuel flow is stopped, deactivate ESP, wet cyclone, and SNCR system.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

   Biomass Handling System

3. Emissions Unit Identification Number: **027**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**20**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Enclosures**	
2. Control Device or Method Code(s): **054**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **3,282,050 tons**	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum bagasse throughput rate is based on the maximum 24-hour steam rates for Boiler Nos. 1, 2, 4, 7, and 8 in the crop season and maximum 24-hour steam rates for Boiler Nos. 1, 2, 4, and 8 in the off-crop season. See Attachment USSC-EU2-B6.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:		2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **F**	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: **77**°F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: **20** feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Nonstack Emission Point Height represents the approximate height of the lowest transfer point associated with the bagasse handling and conveying system. Exit Temperature represents an average ambient temperature.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Food and agriculture: fugitive emissions**		
2. Source Classification Code (SCC): **3-02-888-1**	3. SCC Units: **Tons Product**	
4. Maximum Hourly Rate: **496.1**	5. Maximum Annual Rate: **3,282,050**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Segment refers to bagasse throughput for entire bagasse handling system. Hourly rate refers to maximum hourly rate during the crop season. Annual rate is based on maximum bagasse usage during the crop season by Boiler Nos. 1, 2, 4, 7, and 8 and maximum bagasse usage during the off-crop season by Boiler Nos. 1, 2, 4, and 8.**		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	054		NS
PM_{10}	054		NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **90**
3. Potential Emissions: **1.3** lb/hour **5.25** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Continuous Drop Equation** Reference: **AP-42, Section 13.2.4**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment USSC-EU2-F10.**	
11. Potential Fugitive and Actual Emissions Comment: **Hourly emissions based on maximum annual emissions during the off-crop season and 153 days per crop season. Annual emissions based on total of emissions during the crop and off-crop seasons.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control: **90**
3. Potential Emissions: **0.90** lb/hour **3.42** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Continuous Drop Equation** Reference: **AP-42, Section 13.2.4**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment USSC-EU2-F10.**	
11. Potential Fugitive and Actual Emissions Comment: **Hourly emissions based on maximum annual emissions during the crop season and 212 days per crop season. Annual emissions based on total of emissions during the crop and off-crop seasons.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **62.296.320(4)(b), F.A.C. – General Visible Emissions Standard**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **USSC-EU2-I1** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
☒ Not Applicable

6. Compliance Demonstration Reports/Records
☐ Attached, Document ID: _____
Test Date(s)/Pollutant(s) Tested: _____

☐ Previously Submitted, Date: _____
Test Date(s)/Pollutant(s) Tested: _____

☐ To be Submitted, Date (if known): _____
Test Date(s)/Pollutant(s) Tested: _____

☒ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
☒ Attached, Document ID: **Attachment A** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____	☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____	☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____	☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____	☐ Not Applicable
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____	☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: _____	☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____	☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT USSC-EU2-B6

MAXIMUM BAGASSE USAGE

ATTACHMENT USSC-EU2-B6
FUTURE MAXIMUM BAGASSE USAGE IN BOILERS, U.S. SUGAR, CLEWISTON MILL

Boiler No.	Maximum Heat Input Rate [a] (MMBtu/hr)	Crop Season			Off-Crop Season			Maximum Bagasse Usage (TPY)
		Maximum Steam Production [a]	Maximum Bagasse Usage TPH [b]	Maximum Bagasse Usage tons/season [c]	Maximum Steam Production [d]	Maximum Bagasse TPH [b]	Maximum Bagasse tons/season [c]	
1	495	245,000 lb/hr	68.75	349,800	840,000 lb/day [e]	9.82	36,064	385,864
2	447	215,000 lb/hr	62.08	315,880	3,120,000 lb/day [e]	37.54	137,842	453,722
4	600	285,000 lb/hr	83.33	424,000	6,840,000 lb/day [e]	83.33	306,000	730,000
7	738	350,000 lb/hr	102.50	521,520	8,400,000 lb/day [e]	102.50	0	521,520
8	1,077	575,000 lb/hr	149.58	761,080	450,000 lb/hr	117.07	429,863	1,190,943
TOTAL			466.25	2,372,280			909,770	3,282,050

Footnotes:

[a] Based on 24-hr maximum for Boiler No. 8 and the allowables in Permit No. 0510003-017-AV for the remaining boilers. The 24-hr average limit is shown, where applicable.

[b] Based on heat inputs rates and steam production and assuming 3,600 Btu/lb for bagasse (wet).

[c] Based on 212 days during the crop season and 153 days during the off-crop season.

[d] Based on the maximum allowable steam production rates for the off-crop season as presented in Permit No. 0510003-017-AV.
Total from Boiler Nos. 1-4: 10,800,000 lb/24 hr
Boiler No. 7: 8,400,000 lb/24 hr

[e] During the off-crop season, Boiler Nos. 1, 2 and 4 may act as backup units to the primary unit, Boiler No. 7. Operating Boiler Nos. 1, 2, and 4 simultaneously will use more bagasse than operating Boiler No. 7 alone, and so this scenario was used to determine maximum bagasse usage during the off-crop season. The total maximum allowable steam production for Boiler Nos. 1, 2 and 4 is limited to 10,800,000 pounds per day during the off-crop season.

Boiler No. 1: 1,941.2 Btu/lb steam
Boiler No. 2: 1,943.5 Btu/lb steam
Boiler No. 4: 2,110.0 Btu/lb steam
Boiler No. 8: 1,161 Btu/lb steam
Boiler No. 7: 2,109.1 Btu/lb steam

ATTACHMENT USSC-EU2-F10

MAXIMUM FUGITIVE DUST EMISSIONS

ATTACHMENT USSC-EU2-F10a

MAXIMUM FUTURE CROP SEASON FUGITIVE DUST EMISSIONS FROM THE BIOMASS HANDLING SYSTEM, U.S. SUGAR, CLEWISTON

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (a) *(%)*	U WIND SPEED (b) *(MPH)*	UNCONTROLLED PM EMISSION FACTOR (c) *(LB/TON)*	UNCONTROLLED PM_{10} EMISSION FACTOR (c) *(LB/TON)*	CONTROL	CONTROL EFFICIENCY *(%)*	CONTROLLED PM EMISSION FACTOR *(LB/TON)*	CONTROLLED PM_{10} EMISSION FACTOR *(LB/TON)*	ACTIVITY FACTOR	MAXIMUM ANNUAL PM EMISSIONS *(TONS/YR)*	MAXIMUM ANNUAL PM_{10} EMISSIONS *(TONS/YR)*
BAGASSE HANDLING												
MILL NO. 6C to C BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
MILL NO. 7B to B BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	948,912 TPY (h)	0.094	0.045
UPPER LEVEL CONVEYOR C1 TO LOWER LEVEL CONVEYOR C1	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	665,680 TPY (d)	0.066	0.031
UPPER LEVEL CONVEYOR C5 TO LOWER LEVEL CONVEYOR C5	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	521,520 TPY (f)	0.052	0.024
UPPER LEVEL CONVEYOR C12 TO LOWER LEVEL CONVEYOR C12	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	761,080 TPY (g)	0.075	0.036
FRONT-END LOADER TO CONVEYOR C8N	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
FRONT-END LOADER TO CONVEYOR C8S	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C8N TO CONVEYOR C9	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C8S TO CONVEYOR C9	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C9 TO CONVEYOR C10	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C9 TO CONVEYOR C9A (DRY MILL)	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
DRY MILL TO CONVEYOR C9B (DRY MILL)	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C9B TO CONVEYOR C9C (DRY MILL)	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C9C TO CONVEYOR C10	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C10 TO CONVEYOR C1	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C10 TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
TANDEM B TO CONVEYOR C1	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	948,912 TPY (h)	0.094	0.045
CONVEYOR C1 TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C1 TO CONVEYOR C2	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	283,232 TPY (i)	0.028	0.013
TANDEM C TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
CONVEYOR C2 TO CONVEYOR C3	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C3 TO CONVEYOR C7	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4B	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4A	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
CONVEYOR 4A TO CONVEYOR C12	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
CONVEYOR C12 TO CONVEYOR C7	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR C12 TO CONVEYOR C5	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	521,520 TPY (f)	0.052	0.024
CONVEYOR C4B TO CONVEYOR C5	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR 10A TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C7 TO CONVEYOR C7A	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR C7A TO CONVEYOR C10A	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR 10A TO CONVEYOR C2	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR C7 TO BAGASSE PILE	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
BAGACILLO SYSTEM												
BAGACILLO CYCLONE	POINT SOURCE	--	--	--	--	--	99.999	--	--	178,080 TPY (k)	1.781	1.781
TOTAL											2.862	2.292

Notes/References

(a) Based on the upper value of the range presented in AP-42 that is applicable for the drop equation (Section 13.2.4).

(b) Based on the average of meteorological data from Palm Beach International Airport, 1991-1995. Only data for crop season months were used (November-April).

(c) Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1995) Section 13.2.4:

E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM and 0.35 for PM10.

(d) Based on maximum bagasse consumption during the crop season for Boiler Nos. 1 and 2. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(e) Based on maximum bagasse consumption during the crop season for Boiler No. 4. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(f) Based on maximum bagasse consumption during the crop season for Boiler No. 7. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(g) Based on maximum bagasse consumption during the crop season for Boiler No. 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(h) Based on maximum bagasse consumption during the crop season for Boiler Nos. 1, 2, 4, 7, and 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations. The ratio of cane through B tandem to C tandem is 2:3.

(i) Based on excess bagasse from Boiler Nos. 1 and 2.

(j) Based on excess bagasse from Boiler Nos. 7 and 8.

(k) Based on 40 lbs of bagacillo per ton of ground sugar cane and 42,000 tons of cane per day for 212 days per crop season.

ATTACHMENT USSC-EU2-F10b

MAXIMUM FUTURE OFF-CROP SEASON FUGITIVE DUST EMISSIONS FROM THE BIOMASS HANDLING SYSTEM, U.S. SUGAR, CLEWISTON

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (a) (%)	U WIND SPEED (b) (MPH)	UNCONTROLLED PM EMISSION FACTOR (c) (LB/TON)	UNCONTROLLED PM_{10} EMISSION FACTOR (c) (LB/TON)	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED PM EMISSION FACTOR (LB/TON)	CONTROLLED PM_{10} EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM EMISSIONS (TONS/YR)	MAXIMUM ANNUAL PM_{10} EMISSIONS (TONS/YR)
BAGASSE HANDLING												
MILL NO. 6C to C BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
MILL NO. 7B to B BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
UPPER LEVEL CONVEYOR C1 TO LOWER LEVEL CONVEYOR C1	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	173,907 TPY (d)	0.013	0.006
UPPER LEVEL CONVEYOR C5 TO LOWER LEVEL CONVEYOR C5	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
UPPER LEVEL CONVEYOR C12 TO LOWER LEVEL CONVEYOR C12	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	429,863 TPY (e)	0.032	0.015
FRONT-END LOADER TO CONVEYOR C8N	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
FRONT-END LOADER TO CONVEYOR C8S	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
CONVEYOR C8N TO CONVEYOR C9	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
CONVEYOR C8S TO CONVEYOR C9	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
CONVEYOR C9 TO CONVEYOR C10	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C9 TO CONVEYOR C9A (DRY MILL)	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	909,770 TPY (f)	0.067	0.032
DRY MILL TO CONVEYOR C9B (DRY MILL)	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	909,770 TPY (f)	0.669	0.316
CONVEYOR C9B TO CONVEYOR C9C (DRY MILL)	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	909,770 TPY (f)	0.067	0.032
CONVEYOR C9C TO CONVEYOR C10	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	909,770 TPY (f)	0.067	0.032
CONVEYOR C10 TO CONVEYOR C1	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	173,907 TPY (d)	0.013	0.006
CONVEYOR C10 TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	735,863 TPY (h)	0.054	0.026
TANDEM B TO CONVEYOR C1	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C1 TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C1 TO CONVEYOR C2	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
TANDEM C TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C2 TO CONVEYOR C3	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C3 TO CONVEYOR C7	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4B	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4A	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	429,863 TPY (e)	0.032	0.015
CONVEYOR 4A TO CONVEYOR C12	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	429,863 TPY (e)	0.032	0.015
CONVEYOR C12 TO CONVEYOR C7	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C12 TO CONVEYOR C5	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C4B TO CONVEYOR C5	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR 10A TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C7 TO CONVEYOR C7A	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C7A TO CONVEYOR C10A	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR 10A TO CONVEYOR C2	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C7 TO BAGASSE PILE	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	0 TPY	0.000	0.000
BAGACILLO SYSTEM												
BAGACILLO CYCLONE	POINT SOURCE	--	--	--	--	--	99.999	--	--	0 TPY	0.000	0.000
TOTAL											2.383	1.127

Notes/References

(a) Based on the upper value of the range presented in AP-42 that is applicable for the drop equation (Section 13.2.4).

(b) Based on the average of meteorological data from Palm Beach International Airport, 1991-1995. Only data for off-crop season months were used (May-October).

(c) Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1995) Section 13.2.4:
E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM and 0.35 for PM10.

(d) Based on maximum bagasse consumption during the off crop season for Boiler Nos. 1 and 2. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(e) Based on maximum bagasse consumption during the off crop season for Boiler No. 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(f) Based on bagasse being able to travel either through the drying mill to conveyor C10 or directly from conveyor C9 to conveyor C10. Worst-case emissions results from bagasse traveling through the drying mill. Even though the drying mill is only used about 50-percent of the off-crop season, it is assumed that the drying mill is used the entire off-crop season to determine worst-case emissions.

(g) Based on maximum bagasse consumption during the off crop season for Boiler Nos. 1, 2, 4, and 8. Based on assuming 50% of bagasse goes to C8N and 50% of bagasse goes to C8S. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(h) Based on maximum bagasse consumption during the off-crop season for Boiler Nos. 4 and 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

ATTACHMENT USSC-EU2-F10c
FUTURE FUGITIVE DUST EMISSIONS FROM THE BIOMASS HANDLING SYSTEM
U.S. SUGAR, CLEWISTON

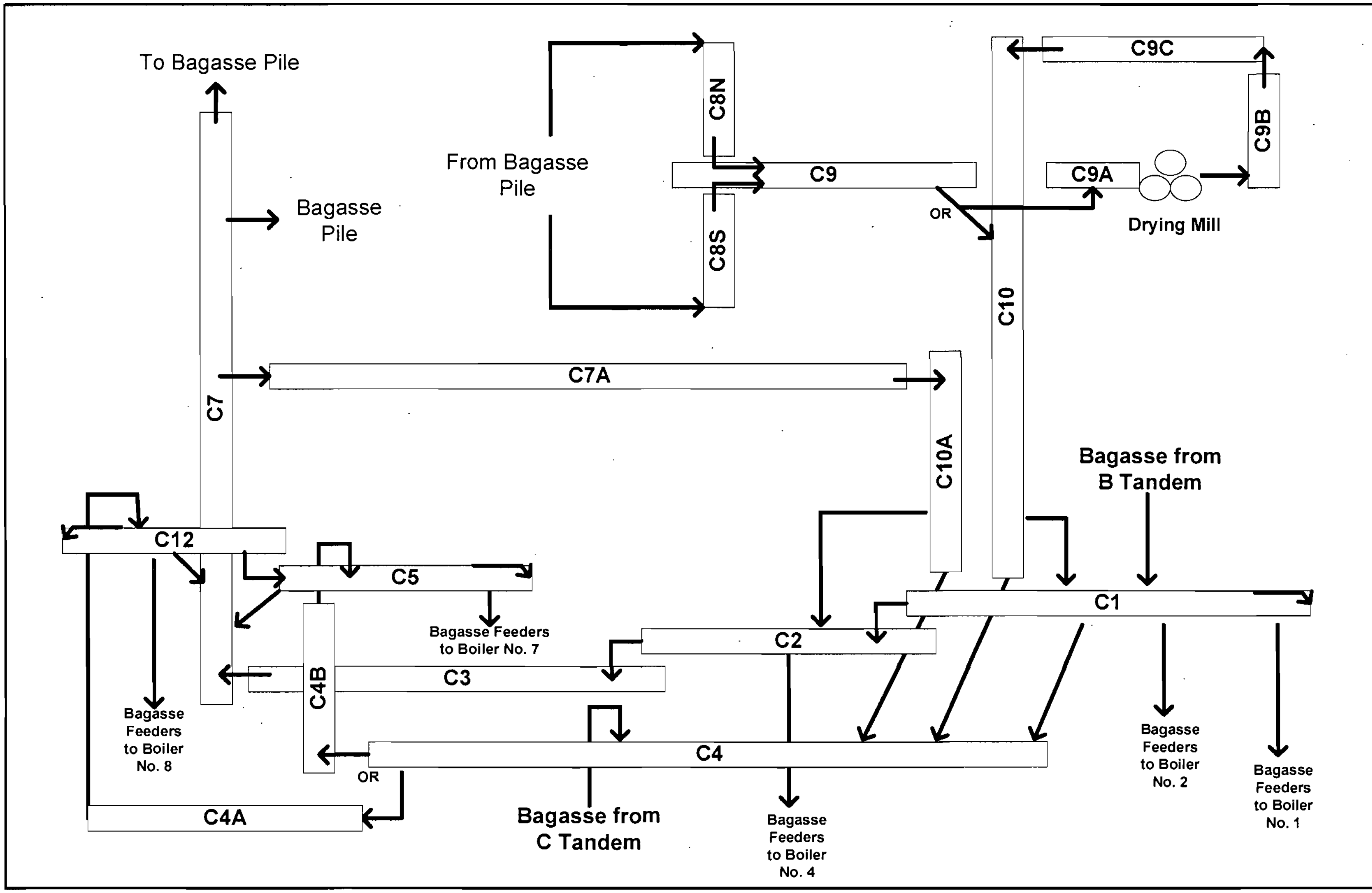
Pollutant	Future Annual Emissions (TPY)		
	Crop Season [a]	Off-Crop Season [b]	Total
BAGASSE HANDLING SYSTEM			
PM	2.862	2.383	5.245
PM_{10}	2.292	1.127	3.419

[a] Emissions from Attachment USSC-EU2-F10a.

[b] Emissions from Attachment USSC-EU2-F10b.

ATTACHMENT USSC-EU2-I1

PROCESS FLOW DIAGRAM



Attachment USSC-EU2-I1
Bagasse Conveying and Handling System
Flow Diagram
U.S. Sugar Clewiston

Process Flow Legend

Solid/Liquid Flow →

Gas Flow - - - →

Filename: 0637563/Boiler #8/4.4/USSC-EU2-I1.vsd

Date: 6/6/06

Golder Associates

ATTACHMENT A

SUPPLEMENTAL INFORMATION FOR CONSTRUCTION PERMIT APPLICATION

TABLE OF CONTENTS

SECTION PAGE

1.0 INTRODUCTION....1

2.0 PROJECT DESCRIPTION....2

2.1 Increased Boiler Steam Rate....3

2.2 Increased Boiler Startup Time....3

2.3 Bagasse Conveying and Handling System....5

1.0 INTRODUCTION

United States Sugar Corporation (U.S. Sugar) owns and operates a sugar mill and refinery located in Clewiston, Hendry County, Florida. The mill and refinery currently operate under Permit No. 0510003-017-AV. U.S. Sugar harvests sugarcane and transports it to the Clewiston Mill, where the cane is processed into raw sugar in the mill. U.S. Sugar processes most of the raw sugar into refined white sugar in an onsite sugar refinery, while the remaining raw sugar is shipped to customers.

U.S. Sugar operates five sugar mill boilers at the Clewiston Mill. The five boilers provide steam to the sugar mill as well as to the sugar refinery. Boiler Nos. 1, 2, and 4 operate primarily during the crop season, which is typically November through May, to provide steam to the sugar mill and refinery. Boiler Nos. 7 and 8 can operate year-round to provide steam to the sugar mill during the crop season and steam to the sugar refinery during the off-crop season. Boiler Nos. 1, 2, and 4 can operate as backup units during the off-season when Boiler No. 7 is down for maintenance, repair, or during periods of unusually low steam demand.

2.0 PROJECT DESCRIPTION

U.S. Sugar was issued Permit No. 0510003-021-AC/PSD-FL-333 on November 21, 2003 for the construction of Boiler No. 8. Construction on the boiler commenced shortly thereafter, and has since been completed. On November 4, 2004, U.S. Sugar was issued a revised construction permit (Permit No. 0510003-024-AC/PSD-FL-333A), which revised the shakedown period for the boiler, included the selective non-catalytic reduction (SNCR) control system and authorized periods of uncontrolled NO_x emissions. On April 7, 2006, a new revised permit was issued for Boiler No. 8 (Permit No. 0510003-030-AC/PSD-FL-333B) that incorporated the applicable NESHAP Subpart DDDDD provisions, included EPA-approved alternate pH monitoring methods, revised the CO emission standard, and authorized wood chips as an approved fuel.

The purpose of this application is to increase the 1-hour and 24-hour steaming rate on bagasse burning for Boiler No. 8, increase the cold startup time to 8-12 hours, and modify the biomass handling system. The maximum annual heat input rate to the boiler will not change.

The primary reason for increasing the steaming rate for bagasse burning is because the original steaming rates of 550,000 pound per hour (lb/hr) (1-hour) and 500,000 lb/hr (24-hour) were based on vendor design data. The initial startup up of the boiler was March 2005. Since boiler startup, steam production and heat input data, as well as nitrogen oxide (NO_x) and carbon monoxide (CO) emissions data, has been collected by the continuous emissions monitoring system (CEMS), and it has been determined that the boiler is capable of a higher steaming rate than originally thought. Through this application, U.S. Sugar is requesting to increase the steam rate to 633,000 lb/hr (1-hour) and 575,000 lb/hr (24-hour), which is equivalent to a maximum heat input of 1,185 million British thermal units per hour (MMBtu/hr) (1-hour) and 1,077 MMBtu/hr (24-hour), respectively.

U.S. Sugar is also requesting that the startup time for the Boiler be increased to 8-12 hours. The original startup time for the boiler was assumed to be 6 hours, which was not based on actual boiler operation. Through the CEMS data, it has become apparent that boiler startup lasts approximately 8-12 hours. The significance of the startup time is reflected in the NO_x limit, which is based on excluding all data corresponding to startups, shutdowns, and malfunctions. The CEMS data has shown that a minimum startup time of 6 hours does not allow the boiler to reach normal operating levels. Therefore, the NO_x 30-day rolling averages, as defined in Permit No. 0510003-030-AC/PSD-

FL-333B, are being overestimated and are not reflecting actual boiler emissions as compared to the permit limit.

U.S. Sugar is also modifying the bagasse handling system, which will result in reduced fugitive particulate matter emissions. The modified system, which includes enclosing most all of the transfer points, installing new conveyors, and upgrading the current conveyor design, will reduce the spillage of bagasse and the amount of windblown bagasse particles.

2.1 Increased Boiler Steam Rate

Boiler No. 8 is currently permitted for a maximum 1-hour steam production rate of 550,000 lb/hr based on a maximum 1-hour heat input rate of 1,030 MMBtu/hr. The maximum continuous steam production capacity is 500,000 lb/hr (24-hour) based on a maximum heat input rate of 936 MMBtu/hr (24-hour). The total maximum heat input from the oil burners is 562 MMBtu/hr.

An analysis of the data generated by the CEMS during the 2005 crop season (November 2005 to mid-April 2006) has revealed that the boiler experiences higher operating loads during the crop season than originally thought. Because of this, we are requesting that the steam production rates be increased to reflect actual operation of the boiler. The revised maximum 1-hour steam production rate is 633,000 lb/hr and the revised maximum 24-hour steam production rate is 575,000 lb/hr. The corresponding revised 1-hour heat input value is 1,185 MMBtu/hr and the revised 24-hour heat input value is 1,077 MMBtu/hr (refer to Attachment USSC-EU1-B6). These short-term heat and steam production increases will not affect the annual capacity of the boiler.

The maximum short-term emissions for Boiler No. 8 will increase as a result of the highest steaming rate of the boiler. Refer to Table 2-1 for the maximum short-term emissions. The maximum annual emissions will not change. In addition, actual operation of the boiler will not change, so therefore, no other units at the Clewiston Mill will be affected as a result of the increased steaming rate.

2.2 Increased Boiler Startup Time

U.S. Sugar is also requesting that the startup time for the boiler be increased to 8-12 hours. Originally, a cold startup was thought to last 6 hours, but the CEMS data has revealed that the boiler does not reach normal operating conditions and is still experiencing startup conditions up to 12 hours after the burner in the boiler is lit. The worst-case emissions occur when the boiler transitions from burning fuel oil to burning bagasse, which usually occurs in the last 1-3 hours of startup.

Boiler startup is defined by the amount of time it takes the boiler to reach its full steaming rate. During a normal startup, Boiler No. 8 will fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100°F to 120°F per hour, it takes approximately 6 to 7 hours to reach the desired superheater steam temperature of 650°F. At this temperature, the Boiler is brought online (i.e.: steam is sent to the steam header) for another 1 to 2 hours while burning fuel oil. Once the Boiler is online and the temperature is stable, bagasse (and/or wood chips) is fed to the boiler until a fire is established across the entire grate. The full steaming rate can be reached about 1 to 3 hours after first feeding bagasse (and/or wood chips) to the boiler.

U.S. Sugar is concerned about the emissions encountered during the transition to bagasse being counted as normal operation. Because it can take approximately 1 to 3 hours to transition from oil to bagasse, startup should cover at least 1 hour of this transition time. The sum of the minimum amount of time for the boiler to reach each stage in startup is equivalent to 8 hours, but could last up to 12 hours. This will allow the boiler to reach normal operating conditions and will allow the correct amount of data due to startups be excluded from the 30-day rolling averages for NO_x and from control device parameter limits

Additionally, the CEMS data has shown that a minimum startup time of 6 hours does not cover the increased emissions due to the transition from burning oil to burning bagasse. The CEMS data indicates that 8-12 hours of startup time is adequate to accurately represent normal boiler operation. Table 2-2 shows two examples of the oxygen measured at the stack, the first occurring in January 2006 and the second in March 2006. These tables show that startup conditions are lasting longer than originally expected (i.e., greater than 6 hours). The higher oxygen represents unstable boiler operation due to a low flame temperature. Currently, the NO_x 30-day rolling averages, as defined in Permit No. 0510003-030-AC/PSD-FL-333B, are being overestimated due to the exclusion of only 6 hours of emissions due to startup. In addition, startup conditions are excluded from compliance with control device parameter limits set under the Boiler MACT rule. Proposed revised wording for boiler startup, as contained in the PSD permit, Section 4, Appendix F, is as follows:

> Boiler Startup: During a normal startup, Boiler 8 will first fire distillate oil to gradually warm up the boiler components. At a target steam temperature rise of 100°F to 120° F per hour, it will take approximately 6 to 7 hours to reach the desired

superheater steam temperature of 650°F. Once this temperature is reached, the Boiler will continue to warm up and be brought on-line by burning fuel oil for another 1 to 2 hours. Bagasse and/or wood chips will then be fed to the Boiler until a fire is established across the entire grate. The full steaming rate can be reached within 1 to 3 hours after first feeding bagasse and/or wood chips. The entire startup period may last as long as 8 to 12 hours.

2.3 Bagasse Conveying and Handling System

The bagasse conveying and handling system handles the bagasse fuel resulting from the processing of the raw sugar cane at the mill. The bagasse is used as a primary fuel for combustion in Boiler Nos. 1, 2, 4, 7, and 8. Bagasse is conveyed from the sugar cane grinding mills directly to the boilers, or to the bagasse storage pile. Bagasse can also be backfed from the storage pile. Currently, emission controls for the bagasse handling system consist of covered conveyors and enclosed transfer points. Fugitive dust emissions may occur from these bagasse conveying and handling activities. As part of the existing system, bagacillo is pneumatically collected from several transfer points and sent directly to the existing bagacillo cyclone. The cyclone is an unregulated permitted air emissions source.

In 2000, U.S. Sugar applied for a construction permit for the addition of six (6) dust collectors to the bagasse handling system. On June 12, 2000, the Florida Department of Environmental Protection (FDEP) issued a construction permit (Permit No. 0510003-11-AC). This permit was later amended on March 7, 2002 (Permit No. 0510003-015-AC) for the installation of only five (5) dust collectors. As of 2004, only two of the five dust collectors have been installed.

The bagasse conveying and handling system is currently undergoing modifications that will result in reduced fugitive particulate matter emissions. The modified system will reduce spillage of bagasse, and is expected to result in a reduction in actual particulate matter (PM) emissions. Two of the five dust collectors were installed on the bagasse conveying and handling system in 2004 to help control fugitive particulate emissions. However, due to maintenance issues, U.S. Sugar is requesting the removal of the dust collectors in addition to making alternative improvements to the bagasse system. These improvements include enclosing almost all of the transfer points, installing new conveyors, and upgrading the current conveyor design.

Enclosing the transfer points greatly reduces the amount of fugitive emissions by reducing the amount of bagasse particles that are exposed to wind and containing the bagasse particles that are suspended during a drop. The only transfer points that are not enclosed include the transfers to and from the bagasse pile and the transfer point associated with conveying bagasse from conveyor C9A to C9B in the drying mill.

In addition, upgrading the existing conveyor design will help reduce fugitive emissions. As bagasse is transferred from one conveyor to another, the force from the dropped bagasse causes the belt to become loose and move up and down. The up and down motion keeps the bagasse suspended in the air instead of allowing it to settle onto the belt. To combat this issue, U.S. Sugar is installing new landing zones for each conveyor that will prevent the belt from moving vertically and create a better enclosure for the conveyors.

The greatest reduction in fugitive emissions will come from the removal of the dust collectors. The estimated decrease is due to assumptions made for the dust collectors (i.e., PM emissions are 0.02 grains/acfm). Due to the nature of the dust collector and the way in which fugitive emissions are callculated from these devices, each dust collector was estimated to emit approximately 1.5 TPY of PM and 1.5 TPY of particulate matter less than 10 microns in diameter (PM_{10}). Emissions based on the current modifications, which include eliminating the dust collectors, enclosing almost all the transfer points, and installing new landing zones on the conveyor belts, are much lower. Maximum crop season fugitive dust emissions for PM are 2.86 TPY and for PM10 are 2.29 TPY. Maximum off-crop season fugitive dust emissions for PM are 1.99 TPY and for PM10 are 0.94 TPY. The basis of these emissions is described below in more detail.

The factors for determining emissions from the bagasse conveying and handling system are based on the equation for fugitive dust emissions from EPA's AP-42 section on aggregate handling and storage piles (Section 13.2.4, 1/95). The moisture content is based on the upper value of the range presented in AP-42 that is applicable to this equation (4.8 percent). The moisture content in bagasse is typically 50 percent; therefore, using a lower moisture content will result in a more conservative estimate of actual emissions. The average annual wind speed is based on 5 years of meteorological data from the Palm Beach International Airport. This meteorological data is typically used to represent the meteorology at the Clewiston Mill site. The average wind speed for the crop season (November through April) was used to quantify emissions from continuous drop and batch drop operations. Most of the transfer points are enclosed to control fugitive dust emissions. The control efficiency for the enclosures is assumed to be 90 percent

Individual activity factors were derived as follows:

- 60 percent of total bagasse produced will come from Tandem C (Mill No. 6C) during the crop season (Tandem C will be in operation for the 2007 crop season),
- 40 percent of total bagasse produced will come from Tandem B (Mill No. 7B) during the crop season,
- Bagasse from the storage pile to conveyors C8N and C8S is split 50/50,
- 100 percent of bagasse goes through the drying mill during the off-crop season (a conservative assumption since the drying mill only operates 50 percent during the off-crop season),
- Estimated bagacillo cyclone efficiency of 99.999 percent,
- The amount of bagasse fed to each boiler is based on the maximum bagasse usage during the crop and off-crop seasons,
- All boilers operate during the crop season, and
- Worst-case emissions are generated by operating Boiler Nos. 1, 2, 4, and 8 during the off-crop season.

The outside bagasse storage pile and associated front-end loaders will not be affected by the changes proposed in this application, so emissions were not estimated for these sources.

The crop season emissions are presented in the application form as Attachment USSC-EU2-F10a. The total PM emissions for the crop-season are estimated at 2.86 TPY and PM_{10} emissions are estimated at 2.29 TPY.

The off-crop season emissions are presented in the application form as Attachment USSC-EU2-F10b. The average wind speed for the off-crop season (May through October) was used. The equation, moisture content and control efficiencies used in the off-crop calculations are the same as the values used for crop season emissions. The activity factors were based on the maximum bagasse consumption for the off-crop season. The maximum off-crop season bagasse consumption was based on steam rate and heat input limits established in Permit No. 0500013-017-AV and the Title V Renewal Application (submitted May 2005). The PM emissions are estimated at 1.99 TPY and the PM_{10} emissions are estimated at 0.94 TPY.

TABLE 2-1
MAXIMUM SHORT-TERM EMISSIONS FOR BOILER NO. 8, U.S. SUGAR CLEWISTON

	Bagasse				No. 2 Fuel Oil				Maximum
Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emissions for any fuel (lb/hr)
Particulate Matter (PM)									
1-hr Average	0.025	(1)	1,185	29.6	0.03	(1)	562	16.86	29.6
24-hr Average	0.025	(1)	1,077	26.9	--		--	--	26.9
Particulate Matter (PM_{10})									
1-hr Average	0.025	(2)	1,185	29.6	0.03	(1)	562	16.86	29.6
24-hr Average	0.025	(2)	1,077	26.9	--		--	--	26.9
Sulfur Dioxide (SO_2)									
1-hr Average	0.06	(2)	1,185	71.1	0.05	(7)	562	28.10	71.1
24-hr Average	0.06	(2)	1,077	64.6	--		--	--	64.6
Nitrogen Oxides (NO_x)									
1-hr Average	0.30	(3)	1,185	355.5	0.14	(2)	562	78.68	355.5
24-hr Average	0.30	(3)	1,077	323.1	--		--	--	323.1
Carbon Monoxide (CO)									
1-hr Average	6.5	(4)	1,185	7,702.5	0.036	(8)	562	20.2	7,702.5
24-hr Average	6.5	(4)	1,077	7,000.5	--		--	--	7,000.5
Volatile Organic Compounds (VOC)									
1-hr Average	0.05	(2)	1,185	59.3	0.0014	(8)	562	0.79	59.3
24-hr Average	0.05	(2)	1,077	53.9	--		--	--	53.9
Sulfuric Acid Mist (SAM)									
1-hr Average	0.0037	(5)	1,185	4.35	0.0015	(5)	562	0.8430	4.4
24-hr Average	0.0037	(5)	1,077	3.96	--		--	--	4.0
Lead (Pb)									
1-hr Average	1.6E-05	(6)	1,185	0.018	9.0E-06	(8)	562	5.1E-03	0.018
24-hr Average	1.6E-05	(6)	1,077	0.017	--		--	--	0.017
Mercury (Hg)									
1-hr Average	3.0E-06	(1)	1,185	0.0036	3.0E-06	(8)	562	1.7E-03	0.004
24-hr Average	3.0E-06	(1)	1,077	0.0032	--		--	--	0.003
Fluorides (Fl)									
1-hr Average	6.0E-04	(7)	1,185	0.711	--		--	--	0.7
24-hr Average	6.0E-04	(7)	1,077	0.646	--		--	--	0.6

References:

1. MACT limit, 40 CFR 63, Subpart DDDDD, Table 1.
2. BACT limit. BACT limit for PM_{10} set equal to the MACT limit for simplicity. BACT limit for NO_x based on a 30-day rolling average.
3. Based on worst-case uncontrolled emissions without the SNCR system.
4. Represents startup or wet fuel conditions (i.e., worst-case emissions).
5. Based on the SO_2 emission factor and a 5% of conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Based on worst-case bagasse analysis for Clewiston mill and assuming 50 percent removal in wet scrubber/ESP, based on stack testing (3.09E-5 lb/MMBtu x 0.50 = 1.55E-5 lb/MMBtu).
7. Based on stack test data from a similar boiler.
8. From AP-42, Section 1.3 for fuel oil combustion:

CO:	5	lb/1,000 gal	Mercury:	3 lb/10^{12} Btu
VOC:	0.2	lb/1,000 gal	Lead:	9 lb/10^{12} Btu

TABLE 2-2
BOILER NO. 8 STARTUP PROCESS STATUS DATA, PERCENT OXYGEN
U.S. SUGAR CLEWISTON

Hour	O_2%	Process Status	Hour	O_2%	Process Status
1/1/06 12:00 AM	Down	Down	3/14/06 1:00 PM	Down	Down
1/1/06 1:00 AM	Down	Down	3/14/06 2:00 PM	Down	Down
1/1/06 2:00 AM	Down	Down	3/14/06 3:00 PM	Down	Down
1/1/06 3:00 AM	Down	Down	3/14/06 4:00 PM	Down	Down
1/1/06 4:00 AM	Down	Down	3/14/06 5:00 PM	Down	Down
1/1/06 5:00 AM	Down	Down	3/14/06 6:00 PM	Down	Down
1/1/06 6:00 AM	Down	Down	3/14/06 7:00 PM	Down	Down
1/1/06 7:00 AM	Down	Down	3/14/06 8:00 PM	Down	Down
1/1/06 8:00 AM	Down	Down	3/14/06 9:00 PM	Down	Down
1/1/06 9:00 AM	Down	Down	3/14/06 10:00 PM	Down	Down
1/1/06 10:00 AM	Down	Down	3/14/06 11:00 PM	Down	Down
1/1/06 11:00 AM	Down	Down	3/15/06 12:00 AM	Down	Down
1/1/06 12:00 PM	**19.6**	**Startup**	3/15/06 1:00 AM	**20.0**	**Startup**
1/1/06 1:00 PM	**19.1**	**Startup**	3/15/06 2:00 AM	**20.5**	**Startup**
1/1/06 2:00 PM	**19.4**	**Startup**	3/15/06 3:00 AM	**19.6**	**Startup**
1/1/06 3:00 PM	**18.8**	**Startup**	3/15/06 4:00 AM	**20.0**	**Startup**
1/1/06 4:00 PM	**19.3**	**Startup**	3/15/06 5:00 AM	**17.7**	**Startup**
1/1/06 5:00 PM	**17.4**	**Startup**	3/15/06 6:00 AM	**17.5**	**Startup**
1/1/06 6:00 PM	**17.0**	**Normal**	3/15/06 7:00 AM	**19.2**	**Normal**
1/1/06 7:00 PM	**14.5**	**Normal**	3/15/06 8:00 AM	**15.5**	**Normal**
1/1/06 8:00 PM	**8.6**	**Normal**	3/15/06 9:00 AM	**7.9**	**Normal**
1/1/06 9:00 PM	4.7	Normal	3/15/06 10:00 AM	5.2	Normal
1/1/06 10:00 PM	3.7	Normal	3/15/06 11:00 AM	5.5	Normal
1/1/06 11:00 PM	3.7	Normal	3/15/06 12:00 PM	4.9	Normal
1/2/06 12:00 AM	3.2	Normal	3/15/06 1:00 PM	4.4	Normal
1/2/06 1:00 AM	3.1	Normal	3/15/06 2:00 PM	4.9	Normal
1/2/06 2:00 AM	3.6	Normal	3/15/06 3:00 PM	4.3	Normal
1/2/06 3:00 AM	4.0	Normal	3/15/06 4:00 PM	4.7	Normal

TABLE 2
LONG STARTUP OPERATIONAL DATA FOR USSC BOILER NO. 8

Hour	Operation Status [a]	Steam Production (klbs)	Heat Input (MMBtu)	O_2 (%)	Wet O_2 (%)	Urea Injection (gal)	NOx (lb/MMBtu)	CO (ppm @ 7% O_2)
11/21/05 5:00	Normal	374.4	702.8	6.8	5.8	39.6	0.17	100.4
11/21/05 6:00	Normal	368.2	690.4	6.9	5.8	41.3	0.17	96.8
11/21/05 7:00	Normal	412.2	767.9	5.4	4.6	45.1	0.15	47.4
11/21/05 8:00	Normal	316.9	588.6	7.1	6.1	29.9	0.14	49.2
11/21/05 9:00	Shutdown	150.9	160.5	9.3	7.9	15.3	0.23	900.1
11/21/05 10:00	Down	Down	Down	Down	Down	Down	Down	Down
11/21/05 11:00	Down	Down	Down	Down	Down	Down	Down	Down
11/21/05 12:00	Startup	0.0	16.3	19.2	18.2	Down	0.17	54.0
11/21/05 13:00	Startup	0.0	39.5	18.5	17.6	Down	0.14	155.8
11/21/05 14:00	Startup	3.1	5.2	17.8	16.9	Down	0.40*	192.4
11/21/05 15:00	Startup	77.6	124.7	15.6	14.5	4.7	0.20	928.7
11/21/05 16:00	Startup	51.2	38.9	14.3	13.1	2.2	0.37	2900.3
11/21/05 17:00	***	251.0	475.0	11.3	10.3	6.2	0.12	1224.2
11/21/05 18:00	***	191.6	206.3	8.3	Invalid	6.8	Invalid	533.7
11/21/05 19:00	***	205.3	299.5	12.4	Invalid	1.4	Invalid	1183.1
11/21/05 20:00	Normal	324.8	608.2	6.4	5.2	5.4	0.11	421.7
11/21/05 21:00	Normal	328.2	613.7	7.0	5.8	8.8	0.12	304.0
11/21/05 22:00	Normal	310.9	581.4	7.1	5.9	0.9	0.11	174.9
11/21/05 23:00	Normal	350.5	658.3	6.3	5.2	4.5	0.09	386.2
12/27/05 16:00	Down	Down	Down	Down	Down	Down	Down	Down
12/27/05 17:00	Down	Down	Down	Down	Down	Down	Down	Down
12/27/05 18:00	Down	Down	Down	Down	Down	Down	Down	Down
12/27/05 19:00	Startup	0.0	48.1	19.4	18.9	Down	0.24	120.5
12/27/05 20:00	Startup	0.0	88.7	19.6	19.2	Down	0.14	140.1
12/27/05 21:00	Startup	0.0	56.3	19.5	19.0	Down	0.24	146.0
12/27/05 22:00	Startup	0.0	56.2	19.5	19.1	Down	0.24	113.2
12/27/05 23:00	Startup	0.0	85.7	19.8	19.4	Down	0.13	130.2
12/28/05 0:00	Startup	0.0	79.6	19.9	19.6	Down	0.09	129.3
12/28/05 1:00	***	0.0	107.3	19.0	18.5	Down	0.10	159.5
12/28/05 2:00	***	32.8	58.9	17.0	16.2	Down	0.29	204.2
12/28/05 3:00	***	121.1	227.8	15.3	14.0	Down	0.13	2153.3
12/28/05 4:00	***	150.1	279.1	12.4	12.2	2.6	0.09	3014.7
12/28/05 5:00	***	418.4	795.3	4.0	4.3	25.8	Inval	1498.9
12/28/05 6:00	Normal	453.1	857.3	5.7	5.6	27.1	0.19	334.7
12/28/05 7:00	Normal	441.0	831.6	6.2	5.7	27.4	0.20	342.0
12/28/05 8:00	Normal	407.0	765.9	6.6	7.1	20.8	Inval	333.7
12/28/05 9:00	Normal	436.9	820.2	6.0	6.2	26.8	Inval	334.5
3/14/06 22:00	Down	Down	Down	Down	Down	Down	Down	Down
3/14/06 23:00	Down	Down	Down	Down	Down	Down	Down	Down
3/15/06 0:00	Down	Down	Down	Down	Down	Down	Down	Down
3/15/06 1:00	Startup	0.4	33.6	20.0	19.3	Down	0.07	65.1
3/15/06 2:00	Startup	0.4	51.7	20.5	19.8	Down	0.03	33.7
3/15/06 3:00	Startup	0.4	58.5	19.6	18.9	Down	0.14	51.2
3/15/06 4:00	Startup	0.4	70.0	20.0	19.2	Down	0.06	104.6
3/15/06 5:00	Startup	0.4	100.4	17.7	16.9	Down	0.19	120.3
3/15/06 6:00	Startup	0.3	105.9	17.5	16.7	Down	0.21	143.9
3/15/06 7:00	***	0.3	79.7	19.2	18.3	Down	0.17	153.7
3/15/06 8:00	***	110.9	208.8	15.5	14.5	0.5	0.12	156.8
3/15/06 9:00	***	271.1	517.9	7.9	6.9	7.4	0.13	428.9
3/15/06 10:00	***	342.1	650.0	5.2	4.2	2.6	0.11	665.5
3/15/06 11:00	Normal	425.7	808.8	5.5	4.4	32.3	0.13	372.4
3/15/06 12:00	Normal	464.8	890.2	4.9	3.8	34.3	0.13	303.2
3/15/06 13:00	Normal	491.8	939.7	4.4	3.5	42.8	0.13	482.3
3/15/06 14:00	Normal	456.5	875.8	4.9	3.8	37.5	0.12	586.7
3/15/06 15:00	Normal	489.7	937.2	4.3	3.4	43.3	0.13	475.1
3/15/06 16:00	Normal	481.3	919.0	4.7	3.7	32.6	0.13	335.6
3/15/06 17:00	Normal	507.5	972.4	5.0	3.8	51.5	0.13	253.9
3/15/06 18:00	Normal	511.3	981.7	4.6	3.6	56.0	0.14	252.1
4/3/06 2:00	Normal	489.2	918.2	5.2	4.1	39.9	0.13	243.3
4/3/06 3:00	Normal	501.2	938.1	5.0	3.9	53.5	0.13	244.2
4/3/06 4:00	Normal	507.0	946.6	5.1	3.9	32.2	0.13	308.4
4/3/06 5:00	Normal	479.0	901.0	5.8	4.5	30.0	0.13	275.7
4/3/06 6:00	Normal	507.7	956.0	5.1	4.0	46.1	0.13	263.2
4/3/06 7:00	Shutdown	288.5	534.4	9.2	8.0	20.3	0.14	196.7
4/3/06 8:00	Down	0.4	Down	21.0	20.3	Down	Down	119.2
4/3/06 9:00	Down	0.3	Down	Down	Down	Down	Down	Down
4/3/06 10:00	Down	0.5	Down	Down	Down	Down	Down	Down
4/3/06 11:00	Down	0.4	Down	Down	Down	Down	Down	Down
4/3/06 12:00	Down	0.4	Down	Down	Down	Down	Down	Down
4/3/06 13:00	Down	0.4	Down	Down	Down	Down	Down	Down
4/3/06 14:00	Startup	0.3	40.1	19.8	19.1	Down	0.11	60.7
4/3/06 15:00	Startup	0.2	61.6	19.0	18.3	Down	0.18	96.6
4/3/06 16:00	Startup	0.2	57.8	19.1	18.4	Down	0.25	62.9
4/3/06 17:00	Startup	0.3	59.3	19.1	18.2	Down	0.22	86.3
4/3/06 18:00	Startup	0.3	55.8	19.2	18.4	Down	0.16	110.5
4/3/06 19:00	Startup	0.3	85.4	18.9	18.1	Down	0.16	150.1
4/3/06 20:00	***	45.4	82.0	16.5	15.3	Down	0.26	668.5
4/3/06 21:00	***	353.7	671.8	3.5	2.6	0.6	0.09	3317.5
4/3/06 22:00	Normal	415.2	777.9	5.5	4.4	33.8	0.14	292.9
4/3/06 23:00	Normal	450.9	843.0	5.2	4.0	34.2	0.12	343.0
4/4/06 0:00	Normal	469.3	876.7	5.1	3.9	42.4	0.15	311.5
4/4/06 1:00	Normal	431.9	807.1	5.6	4.3	33.4	0.13	293.8
4/4/06 2:00	Normal	427.4	798.5	5.7	4.5	28.0	0.13	310.7

Source: Data obtained from the U.S. Sugar CEMS.

[a] Startup is defined as ending when the boiler reaches 200,000 lb/hr steam or the first 6 hours of operation, whichever occurs first. Shutdown is defined as beginning when the fuel feed is terminated (1 hour before going down).

*** Refers to a long startup condition based on either the steam production, heat input, oxygen, urea, or emissions data.

TABLE 8

SUMMARY OF SO_2 FACILITIES CONSIDERED FOR INCLUSION IN THE AAQS AND PSD CLASS II AIR MODELING ANALYSES

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Palm Beach Power [a] X (km)	Relative to Palm Beach Power [a] Y (km)	Distance (km)	Direction (deg)	Maximum SO_2 Emissions (TPY)	Q, Emission Threshold [b] (Dist - SIA) x 20	Include in Modeling Analysis ?
0990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	17.3	-1.7	17.4	96	98	147.7	NO
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-18.5	0.7	18.5	272	173	170.3	YES
na	Glades Electric Cooperative	Hendry	487.1	2957.5	-19.0	0.6	19.0	272	40	180.7	NO
0430008	Atlas-Transoil Inc - South FL Thermal Serv	Hendry	489.2	2966.6	-16.9	9.7	19.5	300	85	189.7	NO
0990332	New Hope Power Partnership (Okeelanta)	Palm Beach	524.1	2940.0	18.0	-16.9	24.7	133	1,999	293.8	YES
0990005	Okeelanta	Palm Beach	525.0	2937.4	18.9	-19.5	27.2	136	51	343.1	NO
0510003	Sugar Cane Growers	Palm Beach	534.9	2953.3	28.8	-3.6	29.0	97	2,555	380.5	YES
0990061	U.S. Sugar -Bryant	Palm Beach	537.8	2969.1	31.7	12.2	34.0	69	2,698	479.3	YES
0990019	Osceola Farms	Palm Beach	544.2	2968.0	38.1	11.1	39.7	74	1,467	593.7	YES
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	46.8	-11.7	48.2	104	954	764.8	YES
0990349	South Florida WMD--Pump Stn. G-310/S-6	Palm Beach	554.2	2940.5	48.1	-16.4	50.8	109	5	816.4	NO
0850001	FPL - Martin	Martin	543.1	2992.9	37.0	36.0	51.6	46	22,982	832.5	YES
0850102	Indiantown Cogeration	Martin	545.6	2991.5	39.5	34.6	52.5	49	2,629	850.2	YES
0990021	Pratt & Whitney (United Technologies)	Palm Beach	562.0	2960.0	55.9	3.1	56.0	87	1,390	919.7	YES
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	44.8	61.2	75.8	36	76	1316.9	NO
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	79.7	3.3	79.8	88	1,533	1395.4	NO
0710019	Lee County Resource Recovery	Lee	424.2	2945.7	-81.9	-11.2	82.7	262	163	1453.2	NO
0710000	FPL - Fort Myers [c]	Lee	422.1	2952.9	-84.0	-4.0	84.1	267	22,702	1481.9	YES
0850021	Stuart Contracting	Martin	575.2	3006.8	69.1	49.9	85.2	54	100	1504.7	NO
0990045	Lake Worth Utilities	Palm Beach	592.8	2943.7	86.7	-13.2	87.7	99	7,415	1554.0	NO
0990568	Lake Worth Generating	Palm Beach	592.8	2943.7	86.7	-13.2	87.7	99	54	1554.0	NO
0990042	FPL -Riviera Beach [c]	Palm Beach	594.2	2960.6	88.1	3.7	88.2	88	73,475	1563.6	YES
0550018	TECO-Phillips	Highlands	464.3	3035.4	-41.8	78.5	88.9	332	4,053	1578.7	NO
0990350	South Florida WMD--Pump Stn. S-9	Broward	555.9	2882.2	49.8	-74.7	89.8	146	2	1595.1	NO
0112534	Enron/Deerfield Beach Energy Center	Broward	583.1	2907.9	77.0	-49.0	91.3	122	166	1625.4	NO
0112545	El Paso Broward Energy Center	Broward	583.3	2908.0	77.2	-48.9	91.4	122	87	1627.7	NO
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	77.5	-49.3	91.9	122	896	1637.0	NO
0112515	Enron/Pompano Energy Center	Broward	583.7	2905.5	77.6	-51.4	93.1	124	166	1661.6	NO
1110003	Fort Pierce Utilities	St. Lucie	566.8	3036.3	60.7	79.4	99.9	37	1,497	1798.9	NO
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	73.5	-73.6	104.0	135	1,318	1880.3	NO
0110037	FPL -Lauderdale [c]	Broward	580.1	2883.3	74.0	-73.6	104.4	135	47,858	1887.4	YES
0110036	FPL -Port Everglades [c]	Broward	587.4	2885.3	81.3	-71.6	108.3	131	170,215	1966.7	YES
0250020	Titan (Tarmac)	Dade	562.9	2861.7	56.8	-95.2	110.9	149	2,792	2017.1	NO
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	58.2	-99.5	115.3	150	857	2105.4	NO
0610029	Vero Beach Power [c]	St. Lucie	567.1	3056.5	61.0	99.6	116.8	31	10,274	2135.9	YES

Note: deg = degrees
km = kilometers
TPY = tons per year

[a] U.S. Sugar Corporation Clewiston Mill' East and North Coordinates (km) are: 506.1 and 2956.9 , respectively.

[b] Based on North Carolina Screening Technique for annual average basis. "Dist" is the distance the facility is located from the project.
"SIA" is the significant impact area. The project's 24-hour SO_2 concentrations are assumed significant out to 10 km from the project.

[c] Large source with annual emissions greater than 10,000 TPY located beyond the screening area (60 km) that were included in the inventory.

TABLE 9
DETAILED SUMMARY OF STACK, OPERATING, AND EMISSIONS DATA OF FACILITIES WITH SO_2 EMISSIONS INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

AIRS Number	Facility Units	Modeling ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Emission Rate 3-Hour lb/hr	3-Hour g/s	24-Hour lb/hr	24-Hour g/s	PSD Source (EXP/CON)	Modeled in AAQS	Modeled in Class II
0510003	US Sugar - Clewiston [c]																		
	PSD Baseline (On-crop season only)																		
	Unit 1 PSD Baseline	USSBRL1B	506.2	2,956.9	75.8	23.1	6.1	1.86	160	344	99.0	30.20	-633.8	-79.86	-462.0	-58.21	EXP	No	Yes
	Unit 2 PSD Baseline	USSBLR2B	506.2	2,956.9	75.8	23.1	6.1	1.86	158	343	117.0	35.70	-633.8	-79.86	-462.0	-58.21	EXP	No	Yes
	Unit 3 PSD Baseline	USSBLR3B	506.2	2,956.9	90.0	27.4	7.5	2.29	156	342	48.2	14.70	-383.3	-48.30	-263.5	-33.20	EXP	No	Yes
	East Pellet Plant PSD Baseline	EPELLET	506.1	2,957.0	40.0	12.2	5.0	1.52	165	347	28.0	8.54	-81.7	-10.30	-81.7	-10.30	EXP	No	Yes
	West Pellet Plant PSD Baseline	WPELLET	506.1	2,957.0	51.5	15.7	5.0	1.52	165	347	28.0	8.54	-81.7	-10.30	-81.7	-10.30	EXP	No	Yes
	On-crop season future																		
	Unit 1	USSBRL1N	506.2	2,956.9	213.0	64.9	8.0	2.44	150	339	82.9	25.30	29.8	3.75	29.8	3.75	CON	Yes	Yes
	Unit 2	USSBLR2N	506.2	2,956.9	213.0	64.9	8.0	2.44	150	339	82.9	25.30	26.8	3.38	26.8	3.38	CON	Yes	Yes
	Unit 4	USSBLR4N	506.1	2,956.9	150.0	45.7	8.2	2.50	160	344	88.7	27.00	38.0	4.79	36.0	4.54	CON	Yes	Yes
	Unit 7	USSBLR7N	506.1	2,957.0	225.0	68.6	8.0	2.44	335	441	94.5	28.80	138.0	17.39	125.5	15.81	CON	Yes	Yes
	Unit 8	USSBLR8N	506.0	2,957.0	199.0	60.7	10.9	3.33	315	430	77.3	23.57	71.1	8.96	64.6	8.14	CON	Yes	Yes
	Off-crop season future																		
	Unit 7	USSBLR7F	506.1	2,957.0	225.0	68.6	8.0	2.44	335	441	94.5	28.80	138.0	17.39	125.5	15.81	CON	Yes	Yes
0510015	Southern Gardens Citrus - PSD																		
	Peel Dryers 1-2	SGARDDRY	487.6	2957.6	125.0	38.1	5.7	1.74	109	316	24.4	7.45	21.0	2.65	21.0	2.65	CON	Yes	Yes
	Boilers 1-4	SGARDBLR	487.6	2957.6	55.0	16.8	4.0	1.22	400	478	46.7	14.22	5.8	0.73	5.8	0.73	CON	Yes	Yes
0990086	New Hope Power Partnership (Okeelanta)																		
	Okeelanta Power Blrs 1,2,3 [b]	OKCOGENF	524.1	2,940.0	199.0	60.7	10.0	3.05	352	451	63.6	19.39	456.3	57.5	456.3	57.5	CON	Yes	Yes
0990016	Sugar Cane Growers [c]																		
	BOILER #1 Future On-crop season	SCG1N	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	58.7	17.90	603.1	75.99	603.1	75.99	CON	Yes	Yes
	BOILER #2 Future On-crop season	SCG2N	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	70.2	21.41	603.1	75.99	603.1	75.99	CON	Yes	Yes
	BOILER #3 Future On-crop season	SCG3N	534.9	2,953.3	180.0	54.9	6.9	2.11	150	339	54.9	16.74	412.8	52.01	412.8	52.01	CON	No	No
	BOILER #4 Future On-crop season	SCG4N	534.9	2,953.3	180.0	54.9	9.4	2.88	150	339	63.3	19.28	1031.9	130.02	1031.9	130.02	CON	No	No
	BOILER #5Future On-crop season	SCG5N	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	92.2	28.10	792.8	99.89	792.8	99.89	CON	No	No
	BOILER #8 Future On-crop season	SCG8N	534.9	2,953.3	155.0	47.2	9.5	2.90	150	339	49.7	15.16	394.4	49.69	394.4	49.69	CON	No	No
	Note: Only SCBLR1N and SCBLR2N were modeleded due to 14 TPD limit																		
	BOILER #1 Future Off-crop season	SCG1F	534.9	2,953.3	150.0	45.7	7.0	2.13	150	339	58.7	17.90	355.6	44.80	255.6	32.20	CON	Yes	Yes
	BOILER #4 Future Off-crop season	SCG4F	534.9	2,953.3	180.0	54.9	9.4	2.88	150	339	63.3	19.28	607.9	76.60	34.1	4.30	CON	Yes	Yes
	BOILER #1 PSD Baseline Off-crop season	SCG1BF	534.9	2,953.3	79.1	24.1	5.5	1.68	395	475	52.3	15.94	-236.5	-29.80	-236.5	-29.80	EXP	No	Yes
	BOILER #2 PSD Baseline Off-crop season	SCG2BF	534.9	2,953.3	79.1	24.1	5.5	1.68	405	480	58.7	17.88	-236.5	-29.80	-236.5	-29.80	EXP	No	Yes
	BOILER #3 PSD Baseline Off-crop season	SCG3BF	534.9	2,953.3	79.1	24.1	5.5	1.68	470	517	54.1	16.50	-177.8	-22.40	-177.8	-22.40	EXP	No	Yes
	BOILER #4 PSD Baseline Off-crop season	SCG4BF	534.9	2,953.3	86.0	26.2	5.3	1.62	149	338	32.4	9.88	-205.6	-25.90	-205.6	-25.90	EXP	No	Yes
	BOILER #5 PSD Baseline Off-crop season	SCG5BF	534.9	2,953.3	79.1	24.1	6.7	2.03	490	528	93.2	28.42	-315.1	-39.70	-315.1	-39.70	EXP	No	Yes
	BOILER #6 PSD Baseline Off-crop season	SCG6BF	534.9	2,953.3	40.0	12.2	5.0	1.52	630	605	21.4	6.53	-147.6	-18.60	-147.6	-18.60	EXP	No	Yes
	BOILER #7 PSD Baseline Off-crop season	SCG7BF	534.9	2,953.3	40.0	12.2	5.0	1.52	630	606	56.4	17.20	-354.0	-44.60	-354.0	-44.60	EXP	No	Yes
	BOILER #1 PSD Baseline On-crop season	SCG1BN	534.9	2,953.3	79.1	24.1	5.5	1.68	395	475	52.3	15.94	-150.0	-18.90	-150.0	-18.90	EXP	No	Yes

TABLE 9

DETAILED SUMMARY OF STACK, OPERATING, AND EMISSIONS DATA OF FACILITIES WITH SO_2 EMISSIONS INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

AIRS Number	Facility Units	Modeling ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	Emission Rate 3-Hour lb/hr	Emission Rate 3-Hour g/s	Emission Rate 24-Hour lb/hr	Emission Rate 24-Hour g/s	PSD Source (EXP/CON)	Modeled in AAQS	Modeled in Class II
	BOILER #2 PSD Baseline On-crop season	SCG2BN	534.9	2,953.3	79.1	24.1	5.5	1.68	405	480	58.7	17.88	-150.0	-18.90	-150.0	-18.90	EXP	No	Yes
	BOILER #3 PSD Baseline On-crop season	SCG3BN	534.9	2,953.3	79.1	24.1	5.5	1.68	470	517	54.1	16.50	-112.7	-14.20	-112.7	-14.20	EXP	No	Yes
	BOILER #4 PSD Baseline On-crop season	SCG4BN	534.9	2,953.3	86.0	26.2	5.3	1.62	149	338	32.4	9.88	-205.6	-25.90	-205.6	-25.90	EXP	No	Yes
	BOILER #5 PSD Baseline On-crop season	SCG5BN	534.9	2,953.3	79.1	24.1	6.7	2.03	490	528	93.2	28.42	0.0	0.00	0.0	0.00	EXP	No	Yes
	BOILER #6 PSD Baseline On-crop season	SCG6BN	534.9	2,953.3	40.0	12.2	5.0	1.52	630	605	21.4	6.53	0.0	0.00	0.0	0.00	EXP	No	Yes
	BOILER #7 PSD Baseline On-crop season	SCG7BN	534.9	2,953.3	40.0	12.2	5.0	1.52	630	606	56.4	17.20	-121.4	-15.30	-121.4	-15.30	EXP	No	Yes
0990061	US Sugar-Bryant [a]																		
	Boiler No 5	USSBRY5	537.8	2,969.1	150.0	45.7	9.5	2.90	161	345	37.7	11.49	613.1	77.25	613.1	77.25	CON	Yes	No
	Boilers No 1,2&3	USBRY123	537.8	2,969.1	65.0	19.8	5.4	1.64	156	342	119.4	36.40	1585.0	199.71	1585.0	199.71	CON	Yes	No
	Diesel Electric Generator Pt 07	USSBRY07	537.8	2,969.1	28.0	8.5	1.2	0.37	475	519	40.0	14.76	28.0	8.41	66.7	8.41	CON	Yes	Yes
	Diesel Electric Generator Pt 08	USSBRY08	537.8	2,969.1	28.0	8.5	1.2	0.37	475	519	42.0	12.19	29.0	8.90	70.6	8.90	CON	Yes	Yes
	Unit 1 PSD Baseline	USSBRY1B	537.8	2,969.1	65.0	19.8	5.5	1.68	430	494	145.3	44.30	-289.7	-36.50	-289.7	-36.50	EXP	No	Yes
	Unit 2&3 PSD Baseline	USBRY23B	537.8	2,969.1	65.0	19.8	5.5	1.68	160	344	124.3	37.90	-579.4	-73.00	-579.4	-73.00	EXP	No	Yes
0990019	Osceola Farms PSD Baseline [a]																		
	Unit 2	OSBLR2	544.2	2,968.0	90.0	27.4	5.0	1.52	154	341	51.9	15.82	135.9	17.12	46.6	5.87	CON	Yes	Yes
	Unit 3	OSBLR3	544.2	2,968.0	90.0	27.4	6.3	1.91	156	342	55.3	16.86	244.0	30.74	50.7	6.39	CON	Yes	Yes
	Unit 4	OSBLR4	544.2	2,968.0	90.0	27.4	6.0	1.83	154	341	54.7	16.67	100.8	12.70	99.3	12.51	CON	Yes	Yes
	Unit 5a	OSBLR5A	544.2	2,968.0	90.0	27.4	5.0	1.52	154	341	54.1	16.48	50.2	6.33	49.7	6.26	CON	Yes	Yes
	Unit 5b	OSBLR5B	544.2	2,968.0	90.0	27.4	5.0	1.52	154	341	54.1	16.48	50.2	6.33	49.7	6.26	CON	Yes	Yes
	Unit 6	OSBLR6	544.2	2,968.0	90.0	27.4	6.2	1.88	154	341	59.7	18.19	265.0	33.39	16.5	2.08	CON	Yes	Yes
	Unit 1 PSD Baseline	OSBLR1B	544.2	2,968.0	72.2	22.0	5.0	1.52	156	342	59.6	18.18	-40.2	-5.07	-40.2	-5.07	EXP	No	Yes
	Unit 2 PSD Baseline	OSBLR2B	544.2	2,968.0	72.2	22.0	5.0	1.52	154	341	59.4	18.10	-129.5	-16.32	-129.5	-16.32	EXP	No	Yes
	Unit 3 PSD Baseline	OSBLR3B	544.2	2,968.0	72.2	22.0	6.3	1.93	154	341	47.6	14.50	-57.6	-7.26	-57.6	-7.26	EXP	No	Yes
	Unit 4 PSD Baseline	OSBLR4B	544.2	2,968.0	72.2	22.0	6.0	1.83	154	341	61.7	18.80	-108.0	-13.61	-108.0	-13.61	EXP	No	Yes
0990016	Atlantic Sugar [a]																		
	Unit 1	ATLSUG1	552.9	2,945.2	90.0	27.4	6.0	1.83	163	346	59.0	17.97	129.2	16.28	129.2	16.28	CON	Yes	Yes
	Unit 2	ATLSUG2	552.9	2,945.2	90.0	27.4	6.0	1.83	170	350	76.6	23.36	129.2	16.28	129.2	16.28	CON	Yes	Yes
	Unit 3	ATLSUG3	552.9	2,945.2	90.0	27.4	6.0	1.83	170	350	70.7	21.56	127.1	16.02	127.1	16.02	CON	Yes	Yes
	Unit 4	ATLSUG4	552.9	2,945.2	90.0	27.4	6.0	1.83	160	344	82.5	25.16	128.7	16.21	128.7	16.21	CON	Yes	Yes
	Unit 5 PSD [b]	ATLSUG5	552.9	2,945.2	90.0	27.4	5.5	1.68	151	339	63.1	19.24	66.7	8.41	63.8	8.04	CON	Yes	Yes
	Unit 1 PSD Baseline	ATLSUG1B	552.9	2,945.2	62.0	18.9	6.3	1.92	451	506	41.7	12.70	-136.8	-17.24	-136.8	-17.24	EXP	No	Yes
	Unit 2 PSD Baseline	ATLSUG2B	552.9	2,945.2	62.0	18.9	6.3	1.92	460	511	35.8	10.90	-178.6	-22.50	-178.6	-22.50	EXP	No	Yes
	Unit 3 PSD Baseline	ATLSUG3B	552.9	2,945.2	71.8	21.9	6.0	1.83	480	522	57.4	17.50	-134.0	-16.88	-134.0	-16.88	EXP	No	Yes
	Unit 4 PSD Baseline	ATLSUG4B	552.9	2,945.2	60.0	18.3	6.0	1.83	160	344	49.2	15.00	-85.4	-10.76	-85.4	-10.76	EXP	No	Yes
990021	Pratt & Whitney (United Technologies)																		
	Heater	PRATARCH	562.0	2960.0	50.0	15.2	3.0	0.91	1000	811	471.6	143.73	111.0	13.99	111.0	13.99	CON	No	No
	Boiler BO-12, -1, -2, -14, -3	PRATBO12	562.0	2,960.0	15.0	4.6	2.5	0.76	500	533	22.7	6.92	0.1	0.012	0.1	0.012	CON	No	No
0850001	FPL Martin																		
	Units 1&2	MART12	543.1	2,992.9	499.0	152.1	26.2	7.99	298	421	69.0	21.03	13839.6	1743.79	13839.6	1743.79	NO	Yes	No
	Units 3&4 PSD	MART34	543.1	2,992.9	213.0	64.9	20.0	6.10	280	411	62.0	18.90	3733.3	470.40	3733.3	470.40	CON	Yes	Yes

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DETAILED SUMMARY OF STACK, OPERATING, AND EMISSIONS DATA OF FACILITIES WITH SO_2 EMISSIONS INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

AIRS Number	Facility Units	Modeling ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	3-Hour lb/hr	3-Hour g/s	24-Hour lb/hr	24-Hour g/s	PSD Source (EXP/CON)	Modeled in AAQS	Modeled in Class II
	Aux Blr PSD	MARTAUX	543.1	2,992.9	60.0	18.3	3.6	1.10	504	535	50.0	15.24	102.4	12.90	102.4	12.90	CON	Yes	Yes
	Diesel Gens PSD	MARTGEN	543.1	2,992.9	25.0	7.6	1.0	0.30	955	786	130.0	39.62	4.0	0.51	4.0	0.51	CON	Yes	Yes
	Unit 8	MART8OIL	543.1	2,992.9	120.0	36.6	19.0	5.79	296	420	73.5	22.40	412.4	51.96	412.4	51.96	CON	Yes.	Yes
0850102	Indiantown Cogernation LP - Indiantown Plant PSD																		
	Polverized Coal Main Boiler	INDTOWN1	545.6	2,990.7	495.0	150.9	16.0	4.88	140	333	93.2	30.50	582.0	73.30	581.7	73.30	CON	Yes	Yes
	Auxiliary and Temporary Boilers	INDTOWN3	545.6	2,990.7	210.0	64.0	5.0	1.52	350	450	87.6	26.70	18.0	2.30	18.3	2.30	CON	Yes	Yes
0110037	FPL - Lauderdale																		
	CTs 1-4 PSD	LAUDU45	580.1	2883.3	150.0	45.7	18.0	5.49	330	439	47.9	14.60	2152.0	271.15	2152.0	271.15	CON	Yes	Yes
	4&5 PSD Baseline	FTLAU45B	580.1	2883.3	151.0	46.0	14.0	4.27	300	422	48.0	14.63	-3627.0	-457.00	-3627.0	-457.00	EXP	No	Yes
0710000	FPL Fort Myers																		
	Unit 1 PSD	FMU1	422.1	2,952.9	301.2	91.8	9.5	2.90	300	422	98.1	29.90	-4646.8	-585.50	-4646.8	-585.50	EXP	No	Yes
	Unit 2 PSD	FMU2	422.1	2,952.9	397.6	121.2	18.1	5.52	275	408	63.0	19.20	-10587.3	-1334	-10587.3	-1334.0	EXP	No	Yes
	HRSGs 1 - 6	FMYHR1_6	422.1	2,952.9	125.0	38.1	19.0	5.79	220	378	46.6	14.2	30.6	3.86	30.6	3.9	CON	Yes	Yes
0990568	Lake Worth Utilities																		
	Unit 3, S-3	LAKWTHU3	592.8	2,943.7	112.9	34.4	7.0	2.13	293	418	51.5	15.70	799.2	100.70	799.2	100.70	NO	Yes	No
	Unit 4, S-4	LAKWTHU4	592.8	2,943.7	115.2	35.1	7.5	2.29	293	418	55.8	17.00	1030.6	129.85	1030.6	129.85	NO	Yes	No
	Unit 5, S-5	LAKWTHU5	592.8	2,943.7	75.1	22.9	10.0	3.05	406	481	91.2	27.80	114.0	14.37	114.0	14.37	CON	Yes	Yes
0990042	FPL Riviera[c]																		
	Units 3&4 at 2.5%s fuel oil	RIVU34	594.2	2,960.6	297.9	90.8	16.0	4.88	263	402	62.0	18.90	16775.0	2113.65	16775.0	2113.65	NO	Yes	No
0610029	Vero Beach Power[c]																		
	Unit 1	VERBU1	567.1	3056.5	200.0	60.96	3.5	1.07	327	437	106.4	32.42	228.3	28.77	228.3	28.77	NO	Yes	No
	Unit 2	VERBU2	567.1	3056.5	200.0	60.96	3.5	1.07	322	434	123.3	37.57	668.3	84.21	668.3	84.21	NO	Yes	No
	Unit 3	VERBU3	567.1	3056.5	200.0	60.96	6.0	1.83	333	440	65.4	19.93	1127.5	142.07	1127.5	142.07	NO	Yes	No
	Unit 4	VERBU4	567.1	3056.5	200.0	60.96	7.0	2.13	306	425	79.9	24.36	548.0	69.05	548.0	69.05	NO	Yes	No
	Unit 5 Simple Cycle CT	VERBU5	567.1	3056.5	125.0	38.1	11.0	3.35	290	416	64.2	19.56	123.0	15.50	123.0	15.50	CON	Yes	Yes
0110036	FPL Port Everglades[c]																		
	Units 1&2 at 2.5%s fuel oil	PTEVU12	587.4	2885.3	342.8	104.5	14.0	4.27	289	415.9	87.7	26.7	12650	1593.9	12650	1593.9	NO	Yes	No
	Units 3&4 at 2.5%s fuel oil	PTEVU34	587.4	2885.3	342.8	104.5	18.1	5.52	287	414.8	78.3	23.9	22000	2772.0	22000	2772.0	NO	Yes	No
	GT 1-12 (0.5% fuel oil)	PTEVGTS	587.4	2885.3	44.0	13.4	15.6	4.75	860	733.2	93.3	28.4	4212	530.7	4212	530.7	NO	Yes	No

[a] Facilities or sources within facilities that operate only during the October 1 through April 30 crop season.

[b] Sugar mill sources that operate all year.

[c] Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.

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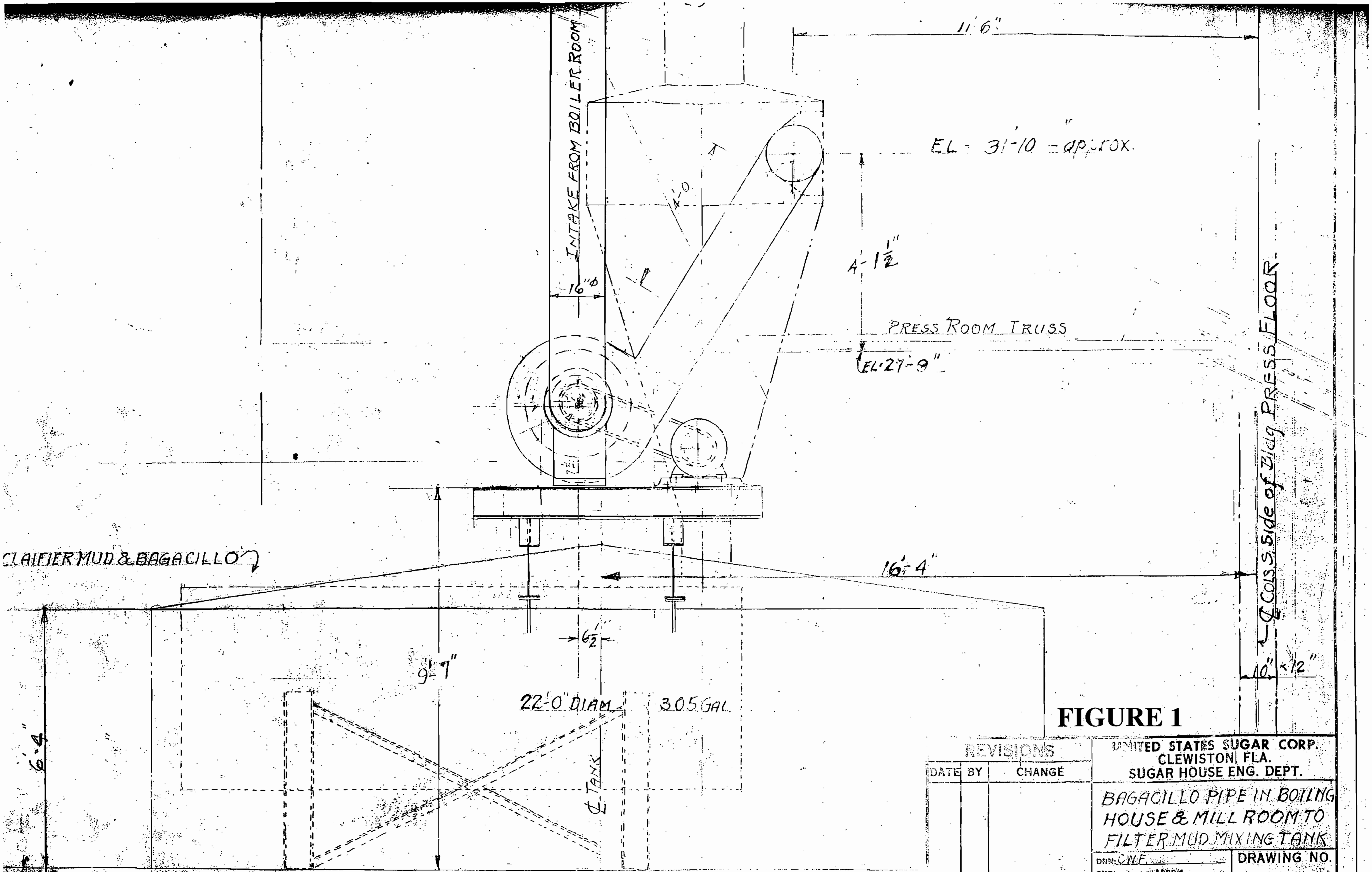

FIGURE 1

REVISIONS			UNITED STATES SUGAR CORP. CLEWISTON, FLA. SUGAR HOUSE ENG. DEPT.
DATE	BY	CHANGE	BAGACILLO PIPE IN BOILING HOUSE & MILL ROOM TO FILTER MUD MIXING TANK
			DRN: C.W.F. CKD: APPD: DRAWING NO.

TABLE 2-1
MAXIMUM SHORT-TERM EMISSIONS FOR BOILER NO. 8, U.S. SUGAR CLEWISTON

	Bagasse				No. 2 Fuel Oil				Maximum
Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emissions for any fuel (lb/hr)
Particulate Matter (PM)									
1-hr Average	0.025	(1)	1,185	29.6	0.03	(1)	562	16.86	29.6
24-hr Average	0.025	(1)	1,077	26.9	--		--	--	26.9
Particulate Matter (PM_{10})									
1-hr Average	0.025	(2)	1,185	29.6	0.03	(1)	562	16.86	29.6
24-hr Average	0.025	(2)	1,077	26.9	--		--	--	26.9
Sulfur Dioxide (SO_2)									
1-hr Average	0.06	(2)	1,185	71.1	0.05	(7)	562	28.10	71.1
24-hr Average	0.06	(2)	1,077	64.6	--		--	--	64.6
Nitrogen Oxides (NO_x)									
1-hr Average	0.30	(3)	1,185	355.5	0.14	(2)	562	78.68	355.5
24-hr Average	0.30	(3)	1,077	323.1	--		--	--	323.1
Carbon Monoxide (CO)									
1-hr Average	6.5	(4)	1,185	7,702.5	0.036	(8)	562	20.2	7,702.5
24-hr Average	6.5	(4)	1,077	7,000.5	--		--	--	7,000.5
Volatile Organic Compounds (VOC)									
1-hr Average	0.05	(2)	1,185	59.3	0.0014	(8)	562	0.79	59.3
24-hr Average	0.05	(2)	1,077	53.9	--		--	--	53.9
Sulfuric Acid Mist (SAM)									
1-hr Average	0.0037	(5)	1,185	4.35	0.0015	(5)	562	0.8430	4.4
24-hr Average	0.0037	(5)	1,077	3.96	--		--	--	4.0
Lead (Pb)									
1-hr Average	1.6E-05	(6)	1,185	0.018	9.0E-06	(8)	562	5.1E-03	0.018
24-hr Average	1.6E-05	(6)	1,077	0.017	--		--	--	0.017
Mercury (Hg)									
1-hr Average	3.0E-06	(1)	1,185	0.0036	3.0E-06	(8)	562	1.7E-03	0.004
24-hr Average	3.0E-06	(1)	1,077	0.0032	--		--	--	0.003
Fluorides (Fl)									
1-hr Average	6.0E-04	(7)	1,185	0.711	--		--	--	0.7
24-hr Average	6.0E-04	(7)	1,077	0.646	--		--	--	0.6

References:
1. MACT limit, 40 CFR 63, Subpart DDDDD, Table 1.
2. BACT limit. BACT limit for PM_{10} set equal to the MACT limit for simplicity. BACT limit for NO_x based on a 30-day rolling average.
3. Based on worst-case uncontrolled emissions without the SNCR system.
4. Represents startup or wet fuel conditions (i.e., worst-case emissions).
5. Based on the SO_2 emission factor and a 5% of conversion of SO_2 to SO_3, and taking into account the ratio of molecular weights (98/80).
6. Based on worst-case bagasse analysis for Clewiston mill and assuming 50 percent removal in wet scrubber/ESP, based on stack testing (3.09E-5 lb/MMBtu x 0.50 = 1.55E-5 lb/MMBtu).
7. Based on stack test data from a similar boiler.
8. From AP-42, Section 1.3 for fuel oil combustion:

CO:	5	lb/1,000 gal	Mercury:	3 lb/10^{12} Btu
VOC:	0.2	lb/1,000 gal	Lead:	9 lb/10^{12} Btu

ATTACHMENT USSC-EU2-F10b

MAXIMUM FUTURE OFF-CROP SEASON FUGITIVE DUST EMISSIONS FROM THE BIOMASS HANDLING SYSTEM, U.S. SUGAR, CLEWISTON

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (a) (%)	U WIND SPEED (b) (MPH)	UNCONTROLLED PM EMISSION FACTOR (c) (LB/TON)	UNCONTROLLED PM_{10} EMISSION FACTOR (c) (LB/TON)	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED PM EMISSION FACTOR (LB/TON)	CONTROLLED PM_{10} EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM EMISSIONS (TONS/YR)	MAXIMUM ANNUAL PM_{10} EMISSIONS (TONS/YR)
BAGASSE HANDLING												
MILL NO. 6C to C BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
MILL NO. 7B to B BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
UPPER LEVEL CONVEYOR C1 TO LOWER LEVEL CONVEYOR C1	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	173,907 TPY (d)	0.013	0.006
UPPER LEVEL CONVEYOR C5 TO LOWER LEVEL CONVEYOR C5	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
UPPER LEVEL CONVEYOR C12 TO LOWER LEVEL CONVEYOR C12	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	429,863 TPY (e)	0.032	0.015
FRONT-END LOADER TO CONVEYOR C8N	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
FRONT-END LOADER TO CONVEYOR C8S	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
CONVEYOR C8N TO CONVEYOR C9	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
CONVEYOR C8S TO CONVEYOR C9	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	454,885 TPY (g)	0.335	0.158
CONVEYOR C9 TO CONVEYOR C10	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C9 TO CONVEYOR C9A (DRY MILL)	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	909,770 TPY (f)	0.067	0.032
DRY MILL TO CONVEYOR C9B (DRY MILL)	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	909,770 TPY (f)	0.669	0.316
CONVEYOR C9B TO CONVEYOR C9C (DRY MILL)	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	909,770 TPY (f)	0.067	0.032
CONVEYOR C9C TO CONVEYOR C10	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	909,770 TPY (f)	0.067	0.032
CONVEYOR C10 TO CONVEYOR C1	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	173,907 TPY (d)	0.013	0.006
CONVEYOR C10 TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	735,863 TPY (h)	0.054	0.026
TANDEM B TO CONVEYOR C1	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C1 TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C1 TO CONVEYOR C2	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
TANDEM C TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C2 TO CONVEYOR C3	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C3 TO CONVEYOR C7	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4B	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4A	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	429,863 TPY (e)	0.032	0.015
CONVEYOR 4A TO CONVEYOR C12	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	429,863 TPY (e)	0.032	0.015
CONVEYOR C12 TO CONVEYOR C7	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C12 TO CONVEYOR C5	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C4B TO CONVEYOR C5	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR 10A TO CONVEYOR C4	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C7 TO CONVEYOR C7A	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C7A TO CONVEYOR C10A	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR 10A TO CONVEYOR C2	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	ENCLOSURE	90	0.00015	0.00007	0 TPY	0.000	0.000
CONVEYOR C7 TO BAGASSE PILE	CONTINUOUS DROP	4.8	8.9	0.00147	0.00070	NONE	0	0.00147	0.00070	0 TPY	0.000	0.000
BAGACILLO SYSTEM												
BAGACILLO CYCLONE	POINT SOURCE	--	--	--	--	--	99.999	--	--	0 TPY	0.000	0.000
TOTAL											**2.383**	**1.127**

Notes/References

(a) Based on the upper value of the range presented in AP-42 that is applicable for the drop equation (Section 13.2.4).

(b) Based on the average of meteorological data from Palm Beach International Airport, 1991-1995. Only data for off-crop season months were used (May-October).

(c) Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1995) Section 13.2.4:
E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM and 0.35 for PM10.

(d) Based on maximum bagasse consumption during the off crop season for Boiler Nos. 1 and 2. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(e) Based on maximum bagasse consumption during the off crop season for Boiler No. 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(f) Based on bagasse being able to travel either through the drying mill to conveyor C10 or directly from conveyor C9 to conveyor C10. Worst-case emissions results from bagasse traveling through the drying mill. Even though the drying mill is only used about 50-percent of the off-crop season, it is assumed that the drying mill is used the entire off-crop season to determine worst-case emissions.

(g) Based on maximum bagasse consumption during the off crop season for Boiler Nos. 1, 2, 4, and 8. Based on assuming 50% of bagasse goes to C8N and 50% of bagasse goes to C8S. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(h) Based on maximum bagasse consumption during the off-crop season for Boiler Nos. 4 and 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

ATTACHMENT USSC-EU2-F10a

MAXIMUM FUTURE CROP SEASON FUGITIVE DUST EMISSIONS FROM THE BIOMASS HANDLING SYSTEM, U.S. SUGAR, CLEWISTON

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (a) (%)	U WIND SPEED (b) (MPH)	UNCONTROLLED PM EMISSION FACTOR (c) (LB/TON)	UNCONTROLLED PM_{10} EMISSION FACTOR (c) (LB/TON)	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED PM EMISSION FACTOR (LB/TON)	CONTROLLED PM_{10} EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM EMISSIONS (TONS/YR)	MAXIMUM ANNUAL PM_{10} EMISSIONS (TONS/YR)
BAGASSE HANDLING												
MILL NO. 6C to C BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
MILL NO. 7B to B BAGASSE BELT CONVEYOR	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	948,912 TPY (h)	0.094	0.045
UPPER LEVEL CONVEYOR C1 TO LOWER LEVEL CONVEYOR C1	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	665,680 TPY (d)	0.066	0.031
UPPER LEVEL CONVEYOR C5 TO LOWER LEVEL CONVEYOR C5	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	521,520 TPY (f)	0.052	0.024
UPPER LEVEL CONVEYOR C12 TO LOWER LEVEL CONVEYOR C12	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	761,080 TPY (g)	0.075	0.036
FRONT-END LOADER TO CONVEYOR C8N	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
FRONT-END LOADER TO CONVEYOR C8S	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C8N TO CONVEYOR C9	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C8S TO CONVEYOR C9	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C9 TO CONVEYOR C10	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C9 TO CONVEYOR C9A (DRY MILL)	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
DRY MILL TO CONVEYOR C9B (DRY MILL)	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
CONVEYOR C9B TO CONVEYOR C9C (DRY MILL)	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C9C TO CONVEYOR C10	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C10 TO CONVEYOR C1	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C10 TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
TANDEM B TO CONVEYOR C1	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	948,912 TPY (h)	0.094	0.045
CONVEYOR C1 TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C1 TO CONVEYOR C2	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	283,232 TPY (i)	0.028	0.013
TANDEM C TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
CONVEYOR C2 TO CONVEYOR C3	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C3 TO CONVEYOR C7	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4B	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C4 TO CONVEYOR C4A	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
CONVEYOR 4A TO CONVEYOR C12	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	1,423,368 TPY (h)	0.141	0.067
CONVEYOR C12 TO CONVEYOR C7	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR C12 TO CONVEYOR C5	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	521,520 TPY (f)	0.052	0.024
CONVEYOR C4B TO CONVEYOR C5	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR 10A TO CONVEYOR C4	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	0 TPY	0.000	0.000
CONVEYOR C7 TO CONVEYOR C7A	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR C7A TO CONVEYOR C10A	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR 10A TO CONVEYOR C2	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	ENCLOSURE	90	0.00020	0.00009	140,768 TPY (j)	0.014	0.007
CONVEYOR C7 TO BAGASSE PILE	CONTINUOUS DROP	4.8	11.2	0.00198	0.00094	NONE	0	0.00198	0.00094	0 TPY	0.000	0.000
BAGACILLO SYSTEM												
BAGACILLO CYCLONE	POINT SOURCE	--	--	--	--	--	99.999	--	--	178,080 TPY (k)	1.781	1.781
TOTAL											**2.862**	**2.292**

Notes/References

(a) Based on the upper value of the range presented in AP-42 that is applicable for the drop equation (Section 13.2.4).

(b) Based on the average of meteorological data from Palm Beach International Airport, 1991-1995. Only data for crop season months were used (November-April).

(c) Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1995) Section 13.2.4:

E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM and 0.35 for PM10.

(d) Based on maximum bagasse consumption during the crop season for Boiler Nos. 1 and 2. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(e) Based on maximum bagasse consumption during the crop season for Boiler No. 4. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(f) Based on maximum bagasse consumption during the crop season for Boiler No. 7. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(g) Based on maximum bagasse consumption during the crop season for Boiler No. 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations.

(h) Based on maximum bagasse consumption during the crop season for Boiler Nos. 1, 2, 4, 7, and 8. See Attachment USSC-EU2-B6 for maximum bagasse consumption calculations. The ratio of cane through B tandem to C tandem is 2:3.

(i) Based on excess bagasse from Boiler Nos. 1 and 2.

(j) Based on excess bagasse from Boiler Nos. 7 and 8.

(k) Based on 40 lbs of bagacillo per ton of ground sugar cane and 42,000 tons of cane per day for 212 days per crop season.