**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. William A. Raiola, V.P. of Sugar Processing Operations

Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
Clewiston Sugar Mill and Refinery
Construction of New Boiler 8

Enclosed is Final Air Permit No. PSD-FL-333, which authorizes the construction of new Boiler 8. The new equipment will be installed at the existing 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 to the draft permit. This final 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 thirty (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 certified mail (*) and copies were mailed by U.S. Mail before the close of business on November 21, 2003 to the persons listed:

Mr. William A. Raiola, USSC*
Mr. Don Griffin, USSC
Mr. Peter Briggs, USSC
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Victoria Gibson     November 21, 2003
(Clerk)     (Date)

November 17, 2003

**PERMITTEE**

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

**PERMITTING AUTHORITY**

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

**PROJECT**

Project No. 0510003-021-AC
Air Permit No. PSD-FL-333

This permit authorizes the construction of Boiler 8, which will be a new 1000 MMBtu per hour bagasse-fired boiler. The new boiler will be installed at the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida.

**NOTICE AND PUBLICATION**

The Department distributed an "Intent to Issue Permit" package on September 25, 2003. The applicant published the "Public Notice of Intent to Issue" in the Clewiston News on October 16, 2003. Proof of publication was provided to the Department on October 24, 2003. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

**COMMENTS**

The following summarizes comments from the applicant the Department's response. The page numbers refer to that of the original Draft Permit.

**DRAFT PERMIT**

**Cover Page**

Expiration Date: The expiration date was changed from December 31, 2006 to July 1, 2007 to allow for the shakedown period, testing, and submittal of a Title V air operation permit.

**Section 3. Subsection A. Boiler 8**

Emissions Unit Description (Page 5 of 14): Clarify that the fuel sulfur content can be up to 0.05% or less by weight. Response: The condition was clarified accordingly.

Specific Condition 1 (Page 5 of 14): Provide a 90 day shakedown period in which Boiler 8 may operate concurrently with the existing boilers, including Boiler 3. U.S. Sugar notes that the Air Quality Analysis showed no significant impacts from the addition of Boiler 8. Also, U.S. Sugar agrees to fire only fuel oil containing 1.6% sulfur by weight or less in Boilers 1 – 3 during the 90-day shakedown period. The current maximum fuel sulfur content for Boilers 1 – 3 during the crop season is 2.5% sulfur by weight. Response: The Department agrees that a limited amount of concurrent operation is appropriate because Boiler 8 will replace Boiler 3 and the newly designed boiler must be fully tested during the active crop season. The Department changed this condition to allow the following:

"The permittee shall have a maximum of 180 days from first fire to perform the necessary shakedown for Boiler 8. During the authorized shakedown period:

- 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.
- 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."

The condition also includes requirements for notifying the Department of first fire in Boiler 8, commencement of commercial operation of Boiler 8, and permanent shutdown of Boiler 3. The shakedown period is consistent with the federal New Source Performance Standards, which allow a maximum 180-day shakedown period to conduct emissions performance tests. It is also consistent with general EPA guidance regarding PSD issues for shakedown periods for replacement units.

Specific Condition 2 (Page 6 of 14): Clarify that the steam conditions of 600 psig and 750° F are "design conditions". Response: The condition was clarified accordingly.

Specific Condition 3 (Page 6 of 14): The application refers to two SNCR systems with slightly different inputs to the automatic control systems. Clarify that the specified parameters represent a broad list of possible inputs to the control system. Response: The condition was clarified accordingly.

Specific Condition 7 (Page 7 of 14): Clarify that the maximum mass emission rates (lb/hour) specified in this condition are based on the 24-hour maximum heat input rate. Response: The condition was clarified accordingly.

a. Ammonia Slip: Delete emission standard for ammonia slip. Although vendor information suggests that the standard is achievable, vendor specifications assume certain operating conditions, which may not be present at all times (testing). A conflict may arise between meeting the NOx standard and meeting the ammonia slip standard. Response: The Department believes that a well designed SNCR system is capable of achieving both the NOx and ammonia slip standards. No changes were made.

b. Carbon Monoxide (CO): Depending on fuel quality and current operating conditions at the mill, CO emissions as determined by a 3-hour test average could be higher than the 0.38 lb/MMBtu currently specified as a "standard based on stack tests". For this reason, the application requests a long-term average for CO emissions based on good combustion and operating practices. It is noted that CO emissions are not subject to a determination of Best Available Control Technology (BACT). U.S. Sugar agrees to install and operate a CEMS to demonstrate compliance with the requested long-term rate. Response: The Department agrees that a long-term standard is appropriate given that CO is not subject to PSD preconstruction review. The CO standard was moved to Specific Condition No. 8 under "Standards Based on CEMS". The averaging period will be identified as a 12-month rolling average. The Department also notes that the proposed federal NESHAP Subpart DDDDD specifies a 24-hour work practice standard for CO emissions. EPA expects to promulgate a final rule by February 2004. The Department will include the final version of this rule when appropriate.

c. Nitrogen Oxides (NOx): Add a note clarifying that the purpose of this "initial demonstration standard" is to show the capabilities of the SNCR system as designed. After the initial test, subsequent compliance will be demonstrated with the long-term CEMS-based standard (30-day rolling average). Response: The condition was clarified accordingly.

Specific Condition 8a (Page 8 of 14): Add the long-term CO standard (12-month rolling average) as previously discussed under Specific Condition No. 7. Response: The following long-term CO emissions standard was added, "As determined by CEMS data, CO emissions shall not exceed 0.38 lb/MMBtu during any consecutive 12 months excluding periods of startup, shutdown, and malfunction." In addition, the Department clarified that the previously specified annual emissions cap (1285 tons during any consecutive 12 months) *does* include emissions from startups, shutdowns, and malfunctions. This was previously referenced in Condition 12.

Specific Condition 8b (Page 8 of 14): Similar to the short-term NOx standard based on a stack test, revise the long term standard to the traditional units for solid fuel fired boilers (lb/MMBtu of heat input rate). Allow the use of the equivalent emission standard. Response: The Department agrees and revised the NOx standard (30-day rolling average) from "81 ppmvd @ 7% oxygen" to the equivalent terms of "0.14 lb/MMBtu".

Specific Condition 9 (Page 8 of 14): Revise the last sentence that requires submittal of a quarterly report for all malfunctions. Allow the Department to request such reports as allowed by the rule. Response: The Department's intent is to make the permittee provide quarterly summary reports for any malfunctions that result in the exclusion of CO or NOx emissions data as allowed by the permit. The condition was clarified as requested and Condition 25 (new number) was revised to clarify the submittal of quarterly reports for CO and NOx data exclusion due to malfunctions.

Specific Condition 12a (Page 8 of 14): Consistent with the changes discussed under Specific Condition 8a, the Department clarified that emissions during startup, shutdown, and malfunction may be excluded from CO standard of 0.38 lb/MMBtu based on a 12-month rolling average.

Specific Condition 12b (Page 9 of 14): Consistent with revising the terms of the NOx standard as discussed under Specific Condition No. 8b, the Department revised the alternate standard for startups, shutdowns, and malfunctions from "162 ppmvd @ 7% oxygen" to the equivalent terms of "0.28 lb/MMBtu".

Specific Condition 13 (Page 9 of 14): Clarify that the boiler thermal efficiency will be determined by the monitoring of steam parameters. The heat input rate will be calculated by two methods: one using the actual boiler thermal efficiency and one using the design boiler thermal efficiency. Also, clarify that the design boiler efficiency (62%) may be used in any future calculations if the tested boiler thermal efficiency is within 90% of this value. Otherwise, the measured boiler thermal efficiency must be used until a new test is conducted. Response: The condition was clarified accordingly.

Specific Condition 14 (Page 9 of 14): Consistent with the changes previously discussed for Condition 7b regarding the "CO standard based on stack tests", the Department removed the stack test requirement. Compliance with the long-term CO standards will be based on CEMS data. The Department also required the submittal of CO CEMS data collected during each test run conducted for NOx and VOC emissions. Consistent with the changes previously discussed for Condition 7c regarding the "NOx standard based on stack tests", the Department removed the annual test requirement for NOx. After the initial test, compliance will be based on CEMS data.

Specific Condition 18d (Page 11 of 14): Consistent with the previous changes to the units of the NOx standard, the Department revised the recorded units of the CEMS data from "ppmvd @ 7% oxygen" to "lb/MMBtu".

Specific Condition 18e (Page 12 of 14): Consistent with the previous changes to the units of the NOx standard, the Department revised the recorded units of the CEMS data from "ppmvd @ 7% oxygen" to "lb/MMBtu".

Specific Condition 18f (Page 12 of 14): Consistent with the previous changes to the units of the NOx standard, the Department revised the recorded units of the CEMS data from "ppmvd @ 7% oxygen" to "lb/MMBtu".

Specific Condition 19 (Page 12 of 14): On September 22, 2003, EPA Region 4 approved U.S. Sugar's request for an alternate sampling procedure in lieu of a continuous opacity monitoring system. Therefore, the Department deleted this condition requiring a COMS and renumbered the remaining conditions appropriately.

Specific Condition 20, Old Number (Page 12 of 14): The Department revised this condition to reflect EPA Region 4's approval of U.S. Sugar's alternate sampling procedure in lieu of a continuous opacity monitoring system.

Specific Condition 21b, Old Number (Page 13 of 14): U.S. Sugar requests that the 1-hour block average be revised to a 3-hour block average. Response: This request is consistent with the proposed federal NESHAP Subpart DDDDD requirements. The Department agrees and revised accordingly. The Department also clarified that the 3-hour block averages need not include malfunctions, associated repairs, and required QA/QC activities for the continuous monitoring system.

Specific Condition 24, Old Number (Page 14 of 14): Clarify that the bagasse firing rate is a calculated term (based on steam conditions). Response: The condition was revised accordingly.

Specific Condition 26, Old Number (Page 14 of 14): As previously discussed under Condition 9, the Department added the following clarification, "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."

**APPENDICES**

The following corrections and clarifications were also made to the Appendices.

- Page D-2: The repeated definition for "steam generating unit operating day" was removed.
- Page D-2: For §60.43b(b), a note was added to identify that the particulate matter standard is not applicable and to see the note at the end of this section for an explanation.
- Page D-3: For §60.44b(a),(h) and (i), a note was added to identify that the nitrogen oxides standard is not applicable and to see the note at the end of this section for an explanation.
- Page D-3: For §60.45b(a) and (d), the Department believes that the Permitting Note adequately identifies that Subpart Db imposes only an opacity standard for the boiler. No change was made.
- Page D-4: For §60.48b(a), minor changes were made to the Permitting Note to identify that EPA Region 4 approved the Alternate Sampling Procedure in lieu of a COMS.
- Page D-5: For §60.49b(b), minor changes were made to the Permitting Note to identify that EPA Region 4 approved the Alternate Sampling Procedure in lieu of a COMS.
- Page E-1: The BACT standards were revised to equivalent terms consistent with the changes previously discussed for the final permit conditions.
- Page E-2: The text in paragraph "c" was revised to clarify that the permit requires the monitoring and recording of the secondary voltage as an indicator of effective performance of the ESP. It is not a part of the Alternate Sampling Procedure approved by EPA Region 4 for NSPS Subpart Db.
- Page E-2: The text in paragraph "d" was revised to clarify that Boiler 3 must be shut down prior to commercial operation of Boiler 8.

**CONCLUSION**

The Department believes that the changes identified above are appropriate and are not substantial.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

**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-333
Project No. 0510003-021-AC
Facility ID No. 0510003
SIC Nos. 2061, 2062
Permit Expires: July 1, 2007

## FACILITY AND LOCATION

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery, 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 passed through 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

This permit authorizes the construction of Boiler 8 (EU-028), a new bagasse-fired boiler with a maximum heat input rate of 1030 MMBtu/hour. The 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



Michael G. Cooke

Michael G. Cooke, Director
Division of Air Resources Management

11/20/03
Effective Date

## PROJECT DESCRIPTION

The United States Sugar Corporation proposes to construct Boiler 8 (EU-028), which will fire bagasse as the primary 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. Bagasse and distillate oil (≤ 0.05% sulfur by weight) will be used to minimize the potential for 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 bagasse handling system (EU-027), bagasse conveyors will be enclosed and dust collectors installed on the conveyor transfer points. The project will also potentially cause small increases in actual annual emissions from miscellaneous existing activities in the refinery.

## REGULATORY CLASSIFICATION

Title III: The existing facility is a potential 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 source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The existing facility operates units subject to the New Source Performance Standards of 40 CFR 60.

## 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 Requirements

Appendix E. Final BACT Determinations

Appendix F. Good Combustion and Operating Practices

Appendix G. Quarterly CO and NOx Emissions Report

## RELEVANT DOCUMENTS

The permit application and additional information received to make it complete are not a part of this permit; however, the information is specifically related to this permitting action and is 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. All documents related to applications for permits to construct minor sources of air pollution or to operate the facility shall be submitted to the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's South District Office at the above address.
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(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.]

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 the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's South District Office with a copy to the Department's New Source Review Section in the Bureau of Air Regulation. [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.<br>*Fuels*: The primary fuel will be bagasse (SCC No. 1-02-011-01). 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.<br>*Capacity*: The maximum continuous steam production is 500,000 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour averages).<br>*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 minimize the potential for emissions of sulfuric acid mist and sulfur dioxide.<br>*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° F and a volumetric flow rate of 400,000 acfm at 5.5% oxygen (225,000 dscfm at 7% oxygen).<br>*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 ($PM/PM_{10}$), sulfuric acid mist (SAM), sulfur dioxide ($SO_2$), 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); and the federal New Source Performance Standards (NSPS) in Subpart Db (industrial boilers) of 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C. See Appendices C and D of this permit for these applicable requirements.}*

## 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. The permittee shall have a maximum of 180 days from first fire to perform the necessary shakedown for Boiler 8. 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.

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(2)(e) and (g), 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 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse. 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 two wet cyclone collectors 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 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(5)(c), F.A.C.]

## PERFORMANCE REQUIREMENTS

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary 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. [Design; Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

5. Boiler Capacities and Restrictions: The maximum continuous steam production capacity (24-hour average) is 500,000 pounds per hour based on a maximum heat input rate of 936 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 pounds of steam per day (equivalent to 500,000 pounds of steam per hour and 936 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).

   The hours of operation are not restricted (8760 hours/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; Applicant Request; Rules 62-4.070(3), 62-212.400(2)(g), 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(5)(c), 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, 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(5)(c), 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. *{Permitting Note: The Department intends to re-open this permit and include the 40 CFR 63 Subpart DDDDD requirements as appropriate.}* [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 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(5)(c), 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(5)(c), F.A.C.]

   e. Particulate Matter ($PM/PM_{10}$): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.026 lb/MMBtu and 24.3 pounds per hour. [Rule 62-212.400(5)(c), F.A.C.]

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 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400(5)(c), 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 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(5)(c), F.A.C.]

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

a. Carbon Monoxide (CO): As determined by CEMS data, CO emissions shall not exceed 0.38 lb/MMBtu during any consecutive 12 months excluding periods of startup, shutdown, and malfunction. 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(2)(g), 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(5)(c), F.A.C.]

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*: Provided best operational practices are used to minimize emissions, CO CEMS data collected during startups, shutdowns, and malfunctions may be excluded from the determination of compliance with the CO standard based on heat input rate (lb/MMBtu, 12-month rolling average). However, 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).

b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, and malfunction 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 and the permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

4) For the period of excluded data, NOx emissions shall not exceed 0.28 lb/MMBtu based on a block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction (alternative standard).

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.

*{Permitting Note: Alternate emissions standards were specified for carbon monoxide and nitrogen oxides 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.}*

## 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. 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. *{Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}* [Rules 62-212.400(5)(c) 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<br>*{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<br>*{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)<br>*{Note: The method shall be based on a continuous sampling train.}* |
| 18 | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography)<br>*{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(5)(c), 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(5)(c), 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 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*: A representative sample of bagasse 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. <u>CEMS</u>: 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 to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 10 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 automatic dual span capabilities with maximum span values of 1000 ppmvd and 10,000 ppmvd.

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 (CO and 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. *24-Hour Averages (CO)*: Each 24-hour block shall begin at midnight of each operating day and shall be determined by averaging 24 consecutive 1-hour averages for each operating day. If the boiler operates less than 24 hours during the block, the 24-hour average shall be determined by averaging the available valid 1-hour block averages for actual boiler operation. Final results shall be recorded in terms of "lb/MMBtu" and "pounds per day". [Rule 62-212.400(BACT), F.A.C.]

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)*: 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(5)(c), F.A.C.]

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(5)(c), F.A.C.]

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(5)(c), F.A.C.]

22. Wet Cyclone: 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) and a manometer (or equivalent) to monitor the pressure drop (inches of water). 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(5)(c), F.A.C.]

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), 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(BACT), F.A.C.]

25. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, 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.]

## B. Bagasse Handling System

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

| ID | Emission Unit Description |
|---|---|
| 027 | Bagasse Handling System |

### EQUIPMENT

1. Modification of Existing System: The permittee is authorized to 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 handling system. [Design; Rule 62-212.400(2)(e) and (g), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive particulate matter, bagasse conveyors shall be enclosed. Dust collectors shall be installed on the conveyor transfer points. The preliminary design for the bagasse 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 duct collectors described above will be installed.}* [Design]

### 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(5)(c), F.A.C.]

### TESTING REQUIREMENTS

4. Opacity Tests: Within 180 days of completing construction of the bagasse 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 1$^{st}$ to September 30$^{th}$) to demonstrate compliance with the opacity standard. [Rules 62-212.400(5)(c) 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**

## 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;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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

*{Permitting Note: 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(2), F.A.C.]

## NSPS Requirements

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(7)(b), F.A.C.

| EU No. | Description |
|---|---|
| 028 | Boiler 8 – Spreader stoker boiler firing bagasse rated at a maximum continuous steam production rate of 500,000 pounds per hour (24-hour average) |

**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(7)(b), 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.}

<u>§60.40b Applicability and Delegation of Authority</u>

(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 for the new unit.}*

<u>§60.41b Definitions</u>

*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.}*

(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 because no equipment will be necessary to reduce SO2 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 (≤ 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 SO2 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 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.

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

*{Permitting Note: NSPS Subpart Db imposes only an 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 550,000 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. The maximum continuous steam production is 500,000 pounds per hour based on a maximum heat input rate of 936 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. 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.

*Bagasse Handling System*: To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

### 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: Bagasse Handling System* | | |
| Opacity [c] | There shall be no visible emissions (≤ 5% opacity) from the dust collector outlets. | |
| *EU-028: Boiler 8* | | |
| CO [d] | Good Combustion Practices | 0.38 lb/MMBtu, 12-month rolling average<br>1285 tons per consecutive 12 months, (rolling total) |
| NOx | 0.14 lb/MMBtu<br>{Initial demonstration standard; subsequent compliance based on CEMS.} | 0.14 lb/MMBtu, 30-day rolling average (normal operation)<br>0.28 lb/MMBtu, average during startup, shutdown, or malfunction period |
| PM | 0.026 lb/MMBtu | 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.<br>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, 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, 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, or malfunction. The alternate NOx standard then applies, which is an average of the CEMS data for the period of startup or shutdown. The CO monitor shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. 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. 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.

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 this project.

*Determination By:*

Jeffery J. Koerner  11-17-03

Jeff Koerner, P.E., Project Engineer  (Date)
New Source Review Section

*Recommended By:*

Trina L Vielhauer  11/18/03

Trina Vielhauer, Chief  (Date)
Bureau of Air Regulation

*Approved By:*

Michael G. Cooke  11/20/03

Michael G. Cooke, Director  (Date)
Division of Air Resources Management

## 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 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse 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.

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 is 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 during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen based on a 24-hour average, excluding emissions during startup and shutdown. The required carbon monoxide CEMS shall report daily CO emission averages in these units. 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 carbonaceous fuels such as bagasse, 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 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 bagasse 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) |

| **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 ............. _____
   b. Shutdowns ................ _____    d. Total ........................ _____
3. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
4. 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** |
|---|---|
| | |

**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
Vice President of Sugar Processing Operations
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by *(Please Print Clearly)* Lafonda Hammond
B. Date of Delivery 1-24

C. Signature
x Lafonda Hammond ☐ Agent ☐ Addressee

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 *(Copy from service label)*
7000 2870 0000 7028 3512

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

**U.S. Postal Service**
**CERTIFIED MAIL RECEIPT**
***(Domestic Mail Only; No Insurance Coverage Provided)***

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OFFICIAL USE

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|---|---|---|
| Postage | $ | Postmark Here |
| Certified Fee | | |
| Return Receipt Fee (Endorsement Required) | | |
| Restricted Delivery Fee (Endorsement Required) | | |
| **Total Postage & Fees** | **$** | |

***Sent To***
William A. Raiola
***Street, Apt. No.; or PO Box No.***
111 Ponce DeLeon Avenue
***City, State, ZIP+ 4***
Clewiston, FL 33440

PS Form 3800, May 2000 **See Reverse for Instructions**

# Florida Department of Environmental Protection

## Memorandum

TO: Michael G. Cooke, Division of Air Resources Management

THRU: Trina Vielhauer, Bureau of Air Regulation
Al Linero, New Source Review Section

FROM: Jeff Koerner, New Source Review Section

DATE: November 17, 2003

SUBJECT: Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
Construction of New Boiler 8

Attached for your approval and signature is a final permit package that authorizes the construction of Boiler 8, which will be a new 1000 MMBtu per hour bagasse-fired boiler. The new boiler will be installed at the existing Clewiston Sugar Mill and Refinery located in Hendry County, Florida. It will purportedly be the largest bagasse-fired boiler in the United States. The project is a major modification to an existing PSD-major facility and is subject to PSD preconstruction review for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. 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 emissions.

The permit includes emissions standards that represent the Department's determination of the Best Available control Technology (BACT) for each PSD-significant pollutant. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design along with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

The Department distributed an "Intent to Issue Permit" package on September 25, 2003. The applicant published the "Public Notice of Intent to Issue" in the Clewiston News on October 16, 2003. Proof of publication was provided to the Department on October 24, 2003. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. Comments and the Department's response are summarized in the attached Final Determination.

Day #90 is November 30, 2003. I recommend your approval of the attached Final Permit for this project.

Attachments

**Golder Associates Inc.**

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

RECEIVED
OCT 29 2003
BUREAU OF AIR REGULATION

October 28, 2003

0237619

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Attention: Mr. Jeffery Koerner, P. E.

RE: UNITED STATES SUGAR CORPORATION – CLEWISTON MILL
PROPOSED NEW BOILER NO. 8
DRAFT PERMIT NO. 0510003-021-AC/PSD-FL-333 – COMMENTS

Dear Mr. Koerner:

United States Sugar Corporation (U.S. Sugar) and Golder Associates Inc. (Golder) have received the draft PSD permit for Boiler No. 8 dated September 25, 2003. We have reviewed the draft permit and have the following comments on the permit.

**Section 3. Subsection A. Boiler 8**

Emissions Unit Description (Page 5 of 14): Please clarify that the fuel sulfur content can be up to 0.05% by weight.

Specific Condition 1 (Page 5 of 14): Please provide for a 90 day shakedown period in which Boiler 8 may operate concurrently with the existing boilers, including Boiler 3. A limited amount of concurrent operation is appropriate because Boiler 8 must be fully tested during the active crop season. The air quality analysis showed no significant impacts from the addition of Boiler 8. Also, U.S. Sugar agrees to fire only fuel oil containing 1.6-percent sulfur by weight or less in Boilers 1 through 3 during the 90-day shakedown period.

Specific Condition 2 (Page 6 of 14): Clarify that the steam conditions of 600 psig and 750°F are "design conditions".

Specific Condition 3 (Page 6 of 14): The application refers to two SNCR systems with slightly different inputs to the automatic control systems. Clarify that the specified parameters represent a broad list of possible inputs to the control system.

Specific Condition 7 (Page 7 of 14): Please clarify that the maximum mass emission rates (lb/hour) specified in this condition are based on the 24-hour maximum heat input rate.

a. Ammonia Slip: It is requested that the ammonia slip limit be deleted as a permit condition. Although vendor information indicates the limit of 20 ppmvd @ 7-percent oxygen is achievable, the vendor specifications assume certain operating conditions, which may not be present at all times in a bagasse boiler. Also, a conflict may arise between meeting the $NO_x$ limit and meeting the ammonia slip limit. We believe that it is more important to meet the $NO_x$ limit for this boiler.

b. Carbon Monoxide (CO): Depending on fuel quality and current operating conditions at the mill, CO emissions, as determined by a 3-hour test average, could be higher than the 0.38-lb/MMBtu currently specified as a "standard based on stack tests". For this reason, U.S. Sugar requests a long-term average for CO emissions based on good combustion and operating practices. It is noted that CO emissions are not subject to a determination of Best Available Control Technology (BACT). U.S. Sugar agrees to install and operate a CEMS to demonstrate compliance with the requested long-term rate.

c. Nitrogen Oxides ($NO_x$): Add a note clarifying that the purpose of the "initial demonstration standard" is to show the capabilities of the SNRC system as designed. After the initial test, subsequent compliance will be demonstrated with the long-term CEMS-based standard (30-day rolling average).

Specific Condition 8a (Page 8 of 14): Add the long-term CO standard (12-month rolling average) as previously discussed under Specific Condition No. 7.

Specific Condition 8b (Page 8 of 14): Similar to the short-term $NO_x$ standard based on a stack test, revise the long-term standard to the traditional units for solid fuel-fired boilers (lb/MMBtu of heat input rate). Allow the use of the equivalent emission standard.

Specific Condition 9 (Page 8 of 14): Revise the last sentence that requires submittal of a quarterly report for all malfunctions. Allow the Department to request such reports as allowed by the Rule.

Specific Condition 11 (Page 9 of 14): Revise this condition to allow excess emissions for up to 5 hours during a boiler startup, consistent with the Good Combustion and Operating Practices in Appendix F. Although it is not likely the mass emission limits will be exceeded during such periods since boiler load will be reduced, the limits in lb/MMBtu may be exceeded.

Specific Condition 12a (Page 9 of 14): Consistent with the changes discussed under Specific Condition 8a, clarify that emissions during startup, shutdown, and malfunction may be excluded from the CO standard of 0.38 lb/MMBtu based on a 12-month rolling average.

Specific Condition 12b (Page 9 of 14): Consistent with revising the $NO_x$ standard as discussed under Specific Condition No. 8b, revise the alternate standard (startups, shutdowns, and malfunctions) from "162 ppmvd @ 7% oxygen" to the equivalent of "0.28 lb/MMBtu".

Specific Condition 13 (Page 9 of 14): Clarify that the boiler thermal efficiency will be determined by the monitoring of steam parameters. The heat input rate will be calculated by two methods: one using the actual boiler thermal efficiency, and one using the design boiler thermal efficiency. Also, clarify that the design boiler efficiency (62 percent) may be used in any future calculations if the tested boiler thermal efficiency is within 90 to 110 percent of this value. Otherwise, the measured boiler thermal efficiency must be used until a new test is conducted.

Specific Condition 14 (Page 9 of 14): Consistent with the changes previously discussed for Specific Condition 7b regarding the "CO standard based on stack tests", remove the stack test requirement. Compliance with the long-term CO standards will be based on CEMS data. Also, consistent with the changes previously discussed for Specific Condition 7c regarding the "$NO_x$ standard based on stack tests", remove the annual test requirement for $NO_x$. After the initial test, compliance will be based on CEMS data.

Specific Condition 18d (Page 11 of 14): Consistent with the previous changes to the units of the $NO_x$ standard, please revise the recorded units of the CEMS data from "ppmvd @ 7% oxygen" to "lb/MMBtu".

Specific Condition 18e (Page 12 of 14): Consistent with the previous changes to the units of the $NO_x$ standard, please revise the recorded units of the CEMS data from "ppmvd @ 7% oxygen" to "lb/MMBtu".

Specific Condition 18e (Page 12 of 14): Consistent with the previous changes to the units of the $NO_x$ standard, please revise the recorded units of the CEMS data from "ppmvd @ 7% oxygen" to "lb/MMBtu".

Specific Condition 19 (Page 12 of 14): On September 22, 2003, EPA Region 4 approved U.S. Sugar's request for an alternate sampling procedure in lieu of a continuous opacity monitoring system. Therefore, please delete this condition and renumber the remaining conditions appropriately.

Specific Condition 20 (Page 12 of 14): Revise this condition to reflect EPA Region 4's approval of U.S. Sugar's alternate sampling procedure in lieu of a continuous opacity monitoring system.

Specific Condition 21b (Page 13 of 14): U.S. Sugar requests that the 1-hour block average be revised to a 3-hour block average.

Specific Condition 24 (Page 14 of 14): Clarify that the bagasse firing rate is a calculated term (based on steam conditions).

Specific Condition 26 (Page 14 of 14): As previously discussed under Specific Condition 9, please add the following clarification, "If CO or $NO_x$ 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."

Appendices: Specific comments regarding the appendices have been e-mailed to you. These comments are to correct regulatory citations, clarify the applicability of Subpart Db to the new boiler, and to make the appendices consistent with the draft permit.

Thank you for consideration of these comments. Please call or e-mail me if you have any questions concerning this information.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P. E. # 19011

DB/nav

Enclosure

cc: Don Griffin
Ron Blackburn, DEP
C. Holladay
Y:\Projects\2002\0237619 US Sugar\4\4.1\L102803\L102803.doc
G. Worley, EPA
J. Bunyak, NPS

# SECTION 4. APPENDICES

## Contents

## 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;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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

*{Permitting Note: 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(2), F.A.C.]

## NSPS Requirements

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(7)(b), F.A.C.

| EU No. | Description |
|---|---|
| 028 | Boiler 8 – Spreader stoker boiler firing bagasse rated at a maximum continuous steam production rate of 500,000 pounds per hour (24-hour average) |

**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(7)(b), 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 for the new unit.}*

§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.

~~*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]***

(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 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 $NO_2$), or ***[Not Applicable]***

(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]***

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis. ***[Not Applicable]***

*{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 ~~only~~ distillate oil only during ~~a cold~~ startup or as a supplemental fuel. ~~However, such a startup will last only a few hours before bagasse is introduced.~~ As described in paragraph (c) above, NSPS Subpart Db does not impose a NOx standard for the boiler flue gas when firing distillate oil alone or 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 bagasse and 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 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.~~

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

*{Permitting Note: NSPS Subpart Db imposes only an 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. ***[Note: Alternate Procedure Approved]***

*{Permitting Note: In lieu of the continuous opacity monitoring requirements, the permittee has requested approval from EPA Region 4 for an alternate procedure that includes additional EPA Method 9 observations when firing oil ~~and monitoring the total ESP secondary voltage as an indicator of proper functioning and effective performance of the ESP~~. EPA Region 4 approved the request in a letter dated September 22, 2003}*

§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]***

(d) The owner or operator ........

(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).

(o) All records required under this section .......

(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.

(w) The reporting period for the reports……..

*{Permitting Note: In lieu of the COMS, the permittee has requested approval from EPA Region 4 for an alternate procedure that includes additional Method 9 observations when firing oil ~~and monitoring the total ESP secondary voltage as an indicator of proper functioning and effective performance of the ESP~~. Approval from EPA Region was obtained in a letter dated September 22, 2003. 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.}*

## 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 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. The maximum continuous steam production is 500,000 pounds per hour based on a maximum heat input rate of 936 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. 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.

*Bagasse Handling System*: To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

### 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: Bagasse Handling System* | | |
| Opacity [c] | There shall be no visible emissions (≤ 5% opacity) from the dust collector outlets. | |
| *EU-028: Boiler 8* | | |
| CO [d] | ~~0.38 lb/MMBtu~~<br>~~(Equivalent: 363 ppmvd @ 7% O2)~~<br>Good Combustion Practices | 0.38 lb/MMBtu, 12-month rolling average; and 1285 tons per consecutive 12 months, (rolling total) |
| NOx | 0.14 lb/MMBtu<br>~~(Equivalent: 81 ppmvd @ 7% O2)~~<br>[initial demonstration standard: subsequent compliance based on CEMS] | ~~81 ppmvd @ 7% O2, 30-day rolling average (normal operation)~~<br>~~162 ppmvd @ 7% O2, average during startup or shutdown~~ 0.14 lb/MMBtu, 30-day rolling average |
| PM | 0.026 lb/MMBtu | Not Applicable |
| $SO_2$ (Surrogate for SAM) | 0.06 lb/MMBtu<br>~~(Equivalent: 25 ppmvd @ 7% O2)~~ | 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<br>~~(Equivalent: 111 ppmvd @ 7% O2)~~ | Not Applicable |
| Opacity [c] | During normal operation, stack opacity shall not exceed 20% based on a 6-minute block average.<br>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, 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: CO (Method 10); NOx (Method 7E); PM (Method 5); $SO_2$ (Method 6C); VOC (Methods 18 and 25A, as propane). 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, 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, or malfunction. The alternate NOx standard then applies, which is an average of the CEMS data for the period of startup or shutdown. The CO monitor shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. 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. In lieu of the COMS requirements for Boiler 8, the permittee has requested approval from EPA Region 4 for an alternate sampling procedure that includes additional EPA Method 9 observations when firing oil ~~and monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP~~. ~~If approved by~~ EPA Region 4 approved this request via letter dated September 22, 2003~~, the permittee may use the alternate sampling procedure~~.

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 commercial operation~~g~~ of new Boiler 8.

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 this project.

*Determination By:*

(DRAFT)

Jeff Koerner, P.E., Project Engineer (Date)
New Source Review Section

*Recommended By:*

(DRAFT)

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

*Approved By:*

(DRAFT)

Michael G. Cooke, Director (Date)
Division of Air Resources Management

## 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 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse 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.

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 is 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 during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen based on a 24-hour average, excluding emissions during startup and shutdown. The required carbon monoxide CEMS shall report daily CO emission averages in these units. 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 carbonaceous fuels such as bagasse, 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 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 bagasse combustion on the fuel grate is substantially complete.

Y:\Projects\2002\0237619 US Sugar\4\4.1\L102803\PSD-FL-333 Boiler 8 - App Markup 10-26-2003.doc

## 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) |

| **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 .............. _____
   b. Shutdowns ................ _____     d. Total ........................ _____
3. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
4. 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** |
|---|---|
| | |

# UNITED STATES SUGAR CORPORATION

Post Office Box 1207 • Clewiston, Florida 33440-1207
Telephone 941/983-8121

October 22, 2003

RECEIVED

OCT 24 2003

BUREAU OF AIR REGULATION

Florida Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road
Tallahassee, Fl. 32399-2410

RE: United States Sugar Corporation, Clewiston Mill
Hendry County, Florida
Proposed New Boiler 8 Project
Notice of Intent to Issue Construction Permit
Draft No. 0510003-021-AC

Gentlemen:

We are enclosing the Affidavit of Publication certifying that the "Public Notice of Intent to Issue Construction Permit of reference was duly published in the legal section of the October 16, 2003 issue of the *CLEWISTON NEWS.*

Sincerely,

UNITED STATES SUGAR CORPORATION

Donald Griffin
Manger, Specialty Sugar

MTB:jt
Enclosure

cc: Florida Department of Environmental Protection
Post Office Box 2549
Fort Myers, Florida 33902-2549

W. A. Raiola, USSC
Michael Low, USSC
Peter Briggs, USSC
David Buff, Golder Associates
Q. Kosmer
C. Holladay
A. Blackburn, SD
B. Worley, EPA
G. Bunyak, NPS

# THE CLEWISTON NEWS

RECEIVED
OCT 24 2003
BUREAU OF AIR REGULATION

Published Weekly

Clewiston, Florida

## AFFIDAVIT OF PUBLICATION

State of Florida
County of Hendry

Before the undersigned authority, personally appeared Debra Miller, who on oath says she is the Editor of the Clewiston News, a weekly newspaper published at Clewiston in Hendry County, Florida, that the attached copy of advertisement being a Public Notice of Intent to Issue Air Construction Permit in the matter State of Florida Department of Environmental Protection

Draft Air Permit No. 0510003-021-AC

in the ____________ court, was published in said newspaper in the issue(s) of October 16, 2003

Affiant further says that the said Clewiston News is a newspaper published at Clewiston, in said Hendry County, continuously published in said Hendry County, Florida, each week, and has been entered as periodicals matter at the post office in Clewiston, in said Hendry County, Florida, for a period of one year next preceding the first publication says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Debra Miller

Sworn to and subscribed before me this 16 day of October 2003

Tracy L. Rounds
Notary Public

NOTARY PUBLIC STATE OF FLORIDA
Tracy L. Rounds
Commission #DD161434
Expires: Oct 28, 2006
Bonded Thru
Atlantic Bonding Co., Inc.

**PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Draft Air Permit No. 0510003-021-AC

U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler 8 Project
Hendry County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to U.S. Sugar Corporation (applicant) to construct the new Boiler 8 project at the existing Clewiston Sugar Mill and Refinery located in Hendry County, Florida. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is United States Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

The applicant proposes to construct a spreader stoker boiler with a maximum continuous steam production rate of 500,000 pounds per hour to support the sugar mill and refinery operations of the existing plant. The boiler will fire bagasse as the primary fuel and distillate oil as a restricted alternate fuel for startup and supplemental uses. As part of the project, existing Boiler 3 will be permanently shut down and the bagasse handling system will be modified to accommodate Boiler 8. Actual emissions of several small existing miscellaneous activities in the mill and refinery may also occur.

The existing Clewiston sugar mill and refinery is located in Hendry County, which is in area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to state and federal Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following net potential increases in emissions in terms of "tons per year" (TPY): 55 TPY of carbon monoxide (CO); 0.8 TPY of fluorides (Fl); 0.1 TPY of lead (Pb); 90 pounds per year of mercury (Hg); 431 TPY of nitrogen oxides (NOx); 62 TPY of particulate matter (PM/PM10); 10 TPY of sulfuric acid mist (SAM); 157 TPY of sulfur dioxide (SO2); and 168 TPY of volatile organic compounds (VOC). Emissions of NOx, PM/PM10, SAM, SO2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

In accordance with Rule 62-212.400, F.A.C., the draft permit includes emissions standards that represent the Department's preliminary determination of the Best Available control Technology (BACT) for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, gagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

As part of the required PSD preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The air quality analysis showed no significant impacts from the project for any pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stoen Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. 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 within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of tha agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Physical Address: Suite 4, 111 S. Magnolia Drive
Mailing Address: 2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400
Telephone: 850-488-0114

Florida Department of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 239-332-6975

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed below.
419884 CGS 10/16/03

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

SEP 2 2 2003

RECEIVED
SEP 24 2003
BUREAU OF AIR REGULATION

4APT-ATMB

Mr. Jeff Koerner
New Source Review Section
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Koerner:

We have received your August 20, 2003, request for a determination concerning an alternative monitoring procedure proposed by a facility subject to New Source Performance Standards (NSPS), Subpart Db "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units." The proposed alternative monitoring is for Boiler No. 8 at the U.S. Sugar Corporation facility in Clewiston, Florida. As an alternative to the use of a continuous opacity monitoring system, U.S. Sugar Corporation has proposed the use of additional Environmental Protection Agency (EPA) Reference Method 9 testing. As a basis for their request, the company has referenced a previous EPA Region 4 determination which approved the use of an opacity monitoring alternative for Boiler No. 7 at their facility. Based on a review of U.S. Sugar's request, we have determined that the alternative opacity monitoring approach proposed for Boiler No. 8 is acceptable.

The proposed Boiler No. 8 will primarily fire bagasse, but will also fire No. 2 (distillate) fuel oil (less than 0.05 percent sulfur by weight) as a start-up and supplemental fuel. The boiler will have a ten percent annual capacity factor limit for distillate oil. Subpart Db at §60.48b(a) states that an owner or operator of an affected facility subject to the opacity standard under §60.43b must install, calibrate, maintain, and operate a continuous monitoring system for measuring opacity and record the output of the system. The opacity standard under §60.43b will apply to Boiler No. 8 when distillate oil is being burned. The NSPS General Provisions at §60.13(i)(2) allow owners or operators to propose alternative monitoring methods for infrequently operated sources. In previous determinations, EPA has indicated that an annual capacity factor of ten percent for a Subpart Db affected facility constitutes infrequent operation for purposes of alternative opacity monitoring under §60.13(i)(2).

The U.S. Sugar Corporation's alternative monitoring proposal consists of collecting EPA Reference Method 9 data when firing distillate oil. A twelve minute Reference Method 9 opacity test will be conducted once per daylight shift during the period that the highest oil firing rate occurs, and a twelve minute Reference Method 9 opacity test will be performed when the boiler achieves the normal operational load after a cold boiler startup with distillate oil. As indicated in the September 9, 1995, Region 4 determination for alternative opacity monitoring concerning U.S. Sugar Corporation's Boiler No. 7, a minimum opacity test of twelve minutes will be required to be consistent with Florida regulatory requirements, instead of the 6 minute test required by EPA Reference Method 9. A log containing the information required by EPA Reference Method 9 for each set of observations and the quantity of distillate fuel oil being burned at the time of the observations will be maintained, and reports will be submitted to the State. The boiler manufacturer's maintenance schedule and procedures will be followed. The proposal indicates that a continuous opacity monitor will be required if the annual capacity factor limit of ten percent when using distillate oil is exceeded or the visible emission standard in §60.43b(f) is not regularly met while firing distillate oil. We have determined that the company's proposal for alternative opacity monitoring is acceptable.

U.S. Sugar Corporation has also indicated that after Boiler No. 8 begins operation, they will investigate the use of surrogate parameters for particulate matter emissions. The proposed surrogate parameters, along with parameter ranges indicating compliance, will be submitted along with the company's Title V permit revision application. The company has indicated that a testing program will be conducted to determine if electrostatic precipitator (ESP) power is a reliable indicator of particulate matter emissions for Boiler No. 8. The secondary voltage and current for each ESP field will be measured. Although the use of ESP power as a surrogate parameter appears reasonable, the acceptable parameter ranges and monitoring requirements for verifying compliance will need to be reviewed by the Air Permits Section at EPA Region 4 when the Title V application is submitted.

If there are any questions regarding this letter, please contact Keith Goff of the EPA Region 4 staff at (404)562-9137.

Sincerely yours,

Beverly H. Banister

Beverly H. Banister
Director
Air, Pesticides, and Toxics
Management Division

cc: SD

# Department of
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 25, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation, Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project

Dear Mr. Raiola:

Enclosed is one copy of the draft permit for the proposed new Boiler 8 project to be installed at the existing Clewiston Sugar Mill and Refinery, which is located at the intersection of W.C. Owens Avenue and State Road 832 in Hendry County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, Administrator of the New Source Review Section, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

"More Protection, Less Process"

Printed on recycled paper.

In the Matter of an
Application for Air Permit by:

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

*Authorized Representative:*
Mr. William A. Raiola, V.P. of Sugar Processing Operations

Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
Clewiston Sugar Mill and Refinery
Facility ID No. 0510003
Proposed Boiler 8 Project
Hendry County, Florida

## INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, United States Sugar Corporation, applied on April 02, 2003 to the Department for a permit to construct the proposed new Boiler 8 project at the existing Clewiston Sugar Mill and Refinery located in Hendry County Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit modification is required to perform proposed work. The Department intends to issue this air construction permit modification based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of intent to issue an air construction permit modification. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of the Public Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the Public Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S.

however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Permit package (including the Public Notice, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9/25/2003 to the persons listed:

Mr. William A. Raiola , USSC*
Mr. Don Griffin, USSC
Mr. Peter Briggs, USSC
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Victoria Gibson (Clerk) September 25, 2003 (Date)

**PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Permit No. 0510003-021-AC

U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler 8 Project
Hendry County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to U.S. Sugar Corporation (applicant) to construct the new Boiler 8 project at the existing Clewiston Sugar Mill and Refinery located in Hendry County, Florida. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is United States Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

The applicant proposes to construct a spreader stoker boiler with a maximum continuous steam production rate of 500,000 pounds per hour to support the sugar mill and refinery operations of the existing plant. The boiler will fire bagasse as the primary fuel and distillate oil as a restricted alternate fuel for startup and supplemental uses. As part of the project, existing Boiler 3 will be permanently shut down and the bagasse handling system will be modified to accommodate Boiler 8. Actual emissions of several small existing miscellaneous activities in the mill and refinery may also occur.

The existing Clewiston sugar mill and refinery is located in Hendry County, which is an area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to state and federal Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following net potential increases in emissions in terms of "tons per year" (TPY): 55 TPY of carbon monoxide (CO); 0.8 TPY of fluorides (Fl); 0.1 TPY of lead (Pb); 90 pounds per year of mercury (Hg); 431 TPY of nitrogen oxides ($NO_x$); 62 TPY of particulate matter ($PM/PM_{10}$); 10 TPY of sulfuric acid mist (SAM); 157 TPY of sulfur dioxide ($SO_2$); and 168 TPY of volatile organic compounds (VOC). Emissions of $NO_x$, $PM/PM_{10}$, SAM, $SO_2$, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

In accordance with Rule 62-212.400, F.A.C., the draft permit includes emissions standards that represent the Department's preliminary determination of the Best Available control Technology (BACT) for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

As part of the required PSD preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The air quality analysis showed no significant impacts from the project for any pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. 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 within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Physical Address: Suite 4, 111 S. Magnolia Drive
Mailing Address: 2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114

Florida Department of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 941/332-6975

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

# TECHNICAL EVALUATION
# &
# PRELIMINARY DETERMINATION

## PROJECT

Project No. 0510003-021-AC
Air Permit No. PSD-FL-333
Clewiston Sugar Mill and Refinery
ARMS Facility ID No. 0510003
Proposed Boiler 8 Project

## COUNTY

Hendry County

## APPLICANT

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

## PERMITTING AUTHORITY

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

September 18, 2003

## 1. GENERAL PROJECT INFORMATION

### Application Processing Schedule

| | |
|---|---|
| 01/28/03 | Meeting in Tallahassee; topics included the proposed Boiler 8 project. |
| 03/13/03 | Permit engineer visited the existing facility in Clewiston to discuss the proposed Boiler 8 project. |
| 04/01/03 | Received application to construct Boiler 8. |
| 04/02/03 | Received $7500 PSD application processing fee. |
| 04/18/03 | Meeting in Tallahassee to discuss possible incompleteness issues. |
| 04/25/03 | Requested additional information. |
| 05/02/03 | Requested additional information related to air quality modeling. |
| 05/22/03 | Received additional information (partial). |
| 05/28/03 | Meeting in Tallahassee to discuss remaining additional information. |
| 06/16/03 | Written request for information discussed in 05/28/03 meeting. |
| 07/22/03 | Received additional information; application complete. |

### Facility Description and Location

The United States Sugar Corporation (U.S. Sugar) operates the existing Clewiston sugar mill (SIC No. 2061) and refinery (SIC No. 2062), which are 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 passed through 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.

"Bagasse" is the fibrous material remaining from sugarcane after milling. It is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. The primary air pollution sources currently consist of five boilers that fire bagasse and fuel oil. Particulate matter emissions are controlled with wet scrubbers for Boilers 1 through 4 and with an electrostatic precipitator for Boiler 7. Other air pollution sources in the refinery include a fluidized bed dryer/cooler, a granular carbon regeneration furnace, conditioning silos with dust collectors, vacuum systems, sugar/starch bins, conveyors, and a packaging system.

### Regulatory Categories

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

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

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

PSD: The facility is a PSD-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility operates one or more units subject to New Source Performance Standards of 40 CFR 60.

### Project Description

U.S. Sugar proposes to construct a new boiler to support the sugar mill and refinery operations of the existing plant. The preliminary design for the proposed new boiler (Boiler 8) specifies a membrane wall boiler with balanced draft spreader stoker and supplemental distillate oil firing system. At the time of the application, the exact boiler specifications were being designed to provide more efficient fuel combustion than previous similar bagasse-fired boilers. The following tables summarize the preliminary boiler design specifications and fuel characteristics for the proposed project.

Table 1A. Preliminary Boiler Design

| Parameter | Description |
|---|---|
| Boiler Type | Balanced draft, membrane wall, spreader stoker boiler |
| Primary Solid Fuel Feed | Rotating feeders and pneumatic spreaders feed bagasse onto a traveling grate at a maximum rate of approximately 130 tons per hour |
| Supplemental Fuel | Low NOx burners firing distillate oil with an annual capacity factor of less than 10%; preliminary design incorporates duel-fuel burners with the capacity to fire natural gas |
| Combustion Air | Over-fire air is provided to complete combustion and reduce NOx emissions; under-fire air is provided for combustion and to cool the traveling grate |
| Ash Removal | Submerged conveyor to ash pond |
| Heat Input Rate | 1030 MMBtu/hour (1-hour maximum); 936 MMBtu/hour, continuous (24-hour maximum) |
| Steam Production | 550,000 lb/hour (1-hour maximum); 500,000 lb/hour, continuous (24-hour maximum) |
| Steam Parameters | 600 psig at 750° F and an enthalpy of 1379 Btu/lb |
| Feedwater Parameters | 800 psig at 250° F with an enthalpy of 218 Btu/lb |
| Furnace Volume | 50,520 $ft^3$ |
| Heat Release Rates | 20,497 Btu/$ft^3$ for bagasse; 11,184 Btu/$ft^3$ for distillate oil |
| Thermal Efficiency | 62% |
| Stack Parameters | 13 feet diameter (maximum); 199 feet tall (minimum) |
| Flue Gas | 400,000 acfm at 5.5% $O_2$ and 330° F; (225,000 dscfm at 7% $O_2$ and 330° F) |

Table 1B. Typical Fuel Characteristics for Boiler 8

| Parameter | Bagasse (Primary Fuel) | No. 2 Distillate Oil (Startup/Supplemental Fuel) |
|---|---|---|
| *General Information* | | |
| Density (lb/gallon) | --- | 6.83 |
| Heating Value (Btu/lb) | 3600, wet | 19,910 |
| Heating Value (Btu/gallon) | --- | 135,000 |
| *Ultimate Analysis* | | |
| Carbon | 47.6% | 84.7% |
| Hydrogen | 6.0% | 15.3% |
| Nitrogen | 0.38% | 0.015% |
| Oxygen | 42.1% | 0.38% |
| Sulfur | 0.03-0.07% | 0.05% |
| Ash/Inorganic | 2.6-5.3% | 0.06% |
| Moisture | 49-55% | 0.51% |
| *Expected Maximum Firing Rates* | | |
| Heat Input Rate (MMBtu per hour), 1-hour maximum | 1030 | 562 |
| Heat Input Rate (MMBtu per hour), 24-hour maximum | 936 | 562 |
| Bagasse (tons per hour), 1-hour maximum | 143 | --- |
| Bagasse (tons per day), 24-hour maximum | 3120 | --- |
| Distillate Oil (gallons per hour), 1-hour maximum | --- | 4161 |
| Distillate Oil (gallons per day), maximum | --- | 99,864 |

As shown above, bagasse will be fired as the primary fuel and distillate oil containing no more than 0.05% sulfur by weight will be fired as a startup and supplemental fuel. Distillate oil firing will be limited to an annual capacity factor of less than 10%. This restriction avoids specific requirements of NSPS Subpart Db. Originally, the applicant also proposed natural gas as a startup and supplemental fuel, but later withdrew the request because the supply of natural gas to this site is not expected for several years. It is noted that the preliminary design incorporates dual-fuel burners with the capacity to fire natural gas. The total annual capacity factor for Boiler 8 will be restricted to 75% by limiting the annual steam production to 3.6135 x $10^{+09}$ pounds per year, which is equivalent to 6,767,100 MMBtu/year. U.S. Sugar proposes the following equipment and techniques to control air emissions.

- *Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)*: CO and VOC emissions will be minimized by good combustion design and operating practices.
- *Nitrogen Oxides (NOx): NOx emissions will be reduced by installing and operating a selective non-catalytic reduction (SNCR) system to inject urea.*
- *Particulate Matter (PM/$PM_{10}$)*: Emissions of particulate matter will be reduced by installing and operating a wet cyclone followed by a dry electrostatic precipitator.
- *Sulfur Dioxide ($SO_2$) and Sulfuric Acid Mist (SAM)*: Emissions of $SO_2$ and SAM will be minimized by the firing of low sulfur fuels including bagasse and distillate oil ($\leq 0.05\%$ sulfur by weight).

As part of the project, existing Boiler 3 rated at 130,000 lb/hour of steam will be permanently shut down resulting in emissions decreases. The shutdown of this unit allows the project to avoid PSD applicability for CO emissions. The project also includes slight emissions increases from small units at the sugar refinery and from the additional handling of bagasse.

## 2. APPLICABLE REGULATIONS

### 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.

| Chapter | Description |
|---|---|
| 62-4 | Permitting Requirements |
| 62-204 | Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference |
| 62-210 | Required Permits, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms |
| 62-212 | Preconstruction Review, PSD Requirements, and BACT Determinations |
| 62-213 | Operation Permits for Major Sources of Air Pollution |
| 62-296 | Emission Limiting Standards |
| 62-297 | Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures |

### Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the following sections of the Code of Federal Regulations (CFR).

| Title 40 | Description |
|---|---|
| Part 60 | Subpart A, General Provisions for NSPS Sources |
| | NSPS Subpart Db, Standards of Performance for Industrial–Commercial-Institutional Steam Generating Units |
| | Applicable Appendices |

### PSD Applicability and Preconstruction Review

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant

Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. 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 regulated pollutant, or

≥ 100 tons per year of any regulated pollutant and belonging to one of 28 PSD Major Facility Categories, or

≥ 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates specified in Table 62-212.400-2, 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.

The existing sugar mill and refinery includes boilers with a cumulative heat input rate from fossil fuels greater than 250 MMBtu per hour, which means that it belongs to the "List of 28 PSD Facility Categories" specified in Table 62-212.400-1, F.A.C. For facilities on this list, the threshold for classification as a PSD major source is 100 tons per year. The Clewiston plant is an existing PSD major source of air pollution because the actual and potential emissions for several pollutants emitted from the plant are greater 100 tons per year. The existing plant is located in Hendry County, which is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS). As such, all new projects are reviewed for the applicability of PSD preconstruction review based on the PSD Significant Emission Rates specified in Table 62-212.400-2, F.A.C. Table 2A summarizes the applicant's PSD applicability analysis for project emissions including increases from Boiler 8, decreases from Boiler 3, and miscellaneous sources.

<u>Table 2A</u>. Summary of the Applicant's PSD

| Pollutant | Net Increase, TPY [a] | PSD Threshold, TPY [a] | Subject to PSD Review? |
|---|---|---|---|
| CO | 55 | 100 | No [b] |
| NOx | 431 | 40 | Yes |
| PM/$PM_{10}$ | 62/58 | 15/25 | Yes |
| $SO_2$ | 157 | 40 | Yes |
| VOC | 168 | 40 | Yes |
| SAM | 10 | 7 | Yes |
| Lead | 0.1 | 0.6 | No |
| Mercury | 0.05 | 0.1 | No |
| Fluorides | 0.8 | 3 | No |

a. "TPY" means tons per year.
b. Net CO emissions are below the PSD significant emission rate due to the shutdown of Boiler 3 as par of the project.

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

## 3. AVAILABLE INFORMATION

In addition to information provided and referenced in the application, the Department also relied on the following information.

1. EPA's Handbook titled, "Control Technologies for Hazardous Air Pollutants"; Document No. EPA/625/6-91-014; June 1991; Section 4.10, Electrostatic Precipitators
2. "Air Pollution Control Technology Handbook"; Karl B. Schnelle, Jr. and Charles A. Brown; 2002 by CRC Press LLC; ISBN 0-8493-9588-7; Chapter 24, Electrostatic Precipitators
3. EPA's Guidebook for Course #SI:412B titled, "Electrostatic Precipitator Plan Review"; Document No. EPA 450/2-82-019; July 1983; Section 3 (ESP Design Parameters and Their Effects on Collection Efficiency) and Section 4 (ESP Design Review)
4. De-NOx Technologies (DNT): Internet web site (http://www.de-nox.com/index.htm) and SNCR Proposal
5. Fuel Tech: Internet web site (http://www.fuel-tech.com/home.htm) and SNCR Proposal
6. White Paper titled "Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions"; Prepared by the SNCR Committee of the Institute of Clean Air Companies, Inc.; May 2000
7. White Paper titled "Selective Catalytic Reduction (SCR) for Controlling NOx Emissions"; Prepared by the SCR Committee of the Institute of Clean Air Companies, Inc.; November 1997


## 4. BOILER 8 - CONTROL TECHNOLOGY REVIEW

### MACT Review

On November 26, 2002, EPA proposed Subpart DDDDD, a National Emissions Standard for Hazardous Air Pollutants (NESHAP). The proposed rule establishes maximum achievable control technology (MACT) standards to reduce hazardous air pollutant (HAP) emissions from industrial, commercial and institutional boilers and process heaters. In general, the proposed industrial boiler MACT imposes two primary performance standards: a total particulate matter emission limit of 0.026 lb/MMBtu as surrogate for the reduction of total particulate HAP; and 400 ppmvd @ 3% oxygen as a surrogate for the reduction of total organic HAP. However, the boiler would not be subject to this rule until it becomes final.

Because the above MACT rule is not yet final, the project could be subject to a case-by-case MACT determination in Section 112(g) of the Clean Air Act. The application includes estimated HAP emissions based on the results of HAP testing conducted on the Boiler 7 at the Clewiston Mill. This is a similar, large modern bagasse boiler with a maximum heat input rate of 812 MMBtu per hour. Based on the application, total potential HAP emissions are estimated to be about 14 tons per year, which is below the MACT applicability threshold of 25 tons per year. In addition, no single HAP is estimated to be greater than 10 tons per year. Therefore, the proposed project does not trigger a case-by-case MACT.

### NSPS Review

The proposed new boiler is subject to the New Source Performance Standards (NSPS) in 40 CFR 60, which are adopted by reference in Rule 62-204.800(7)(b), F.A.C. Subpart Db establishes standards, testing, and monitoring provisions for emissions of nitrogen oxides, particulate matter, and sulfur dioxide primarily from industrial boilers firing coal, oil, natural gas, or wood with a maximum heat input rate of more than 100 MMBtu per hour. When firing distillate oil, the proposed boiler has a maximum heat input rate of 562 MMBtu per hour making the unit subject to the applicable Subpart Db requirements.

However, the proposed boiler will fire distillate oil containing no more than 0.05% sulfur by weight limited to an annual capacity factor of less than 10%. As such, Subpart Db establishes the following requirements:

- Sulfur Dioxide ($SO_2$): No specific $SO_2$ standards or percent reduction requirements are imposed because the unit will fire only very low sulfur oil, which is defined in the rule as ≤ 0.5% sulfur by weight. Compliance with the oil specification will be demonstrated by maintaining fuel receipts. [§60.42b (j) and §60.49b (r)]

- Particulate Matter ($PM/PM_{10}$): As specified in the rule, no particulate matter emission standard is imposed because no equipment will be necessary to reduce $SO_2$ emissions. The rule does limit opacity to 20% or less, except for one 6-minute block per hour not to exceed 27%. The opacity standard does not apply during startup, shutdown, or malfunction. A continuous opacity monitoring system (COMS) is required by this rule unless an alternate sampling procedure is approved by EPA. The applicant has requested an alternate monitoring procedure in lieu of the COMS. It is nearly identical to that previously approved by EPA Region 4 for Boiler 7. [§60.43b (b), (f), and (g)]
- Nitrogen Oxides (NOx): As specified in the rule, no NOx standard is imposed because the distillate oil firing is limited to an annual capacity factor of no more than 10%. [§60.44b (c)]

Therefore, the fuel sulfur specification, fuel oil annual capacity factor limit, opacity standard, and COMS are the only NSPS Subpart Db requirements applicable to the proposed boiler.

**Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)**

CO and VOC are emitted as products of incomplete combustion. VOC emissions are significant and require a BACT determination. As proposed, the project did not trigger PSD review for CO emissions due to emissions decreases from the shutdown of Boiler 3, the requested CO emission standards, and the proposed capacity restrictions on Boiler 8. However, in general, the technologies used to control CO and VOC emissions from boilers are similar and will be reviewed together.

CO/VOC - Applicant's Recommendation

The applicant identified the following technologies as available for the control of CO and VOC emissions.

- *Refrigerated Condensers*: Refrigerated surface and contact condensers can be used to cool the exhaust gas and condense out organic compounds from gas streams with high concentrations (~ 5000 ppmv). These units are generally reserved for processes with organic compound concentrations that are much greater than the levels estimated for the proposed boiler (~ 100 ppmvd) and which can isolate a specific compound for reuse or resale. Refrigerated condensers were identified as not feasible for the control of VOC emissions from this project.
- *Carbon Adsorbers*: Gas streams with low flow rates and relatively high organic compound concentrations can be controlled by adsorption onto carbon particles. However, the flue gas exhaust from the proposed boiler will have a high flow rate (~ 400,000 acfm) with a predicted low VOC concentration (~ 100 ppmvd). Carbon adsorbers were identified as not feasible for the control of VOC emissions from this project.
- *Flares*: Gas streams with high concentrations of carbon monoxide and organic compounds can be combusted using specially designed burner tips and auxiliary fuel. For example, large volumes of methane gas collected from active landfills can be combusted in an open flame on an elevated flare. Again, due to the expected low concentrations of these pollutants, flares were identified as not feasible for the project.
- *Catalytic Oxidation*: The reduction of carbon monoxide and organic compounds across a catalyst bed within a given temperature range is recognized as a viable control method. This technology has been applied to reduce CO and VOC emissions from gas turbines as well as VOC emissions from coating lines and flexographic printing operations. Control efficiencies of more than 90% are possible. However, catalysts can be blinded, masked, or poisoned by contaminants in the exhaust gas stream, which can rapidly decrease the control effectiveness and lead to premature replacement. Catalytic incineration is identified as not feasible for the project due to the high uncontrolled particulate loading of the exhaust stream and the potential for catalyst poisoning from expected contaminants resulting from firing biomass.
- *Thermal Oxidation*: The thermal destruction of organic compounds at high temperatures can achieve emission reductions over 90%. However, the project is being designed for uniform fuel firing and high temperatures to provide efficient combustion. The high flue gas flow rate (~ 400,000 acfm) with predicted low concentrations of organic compounds (~ 100 ppmvd) and carbon monoxide (~ 400 ppmvd) represent

difficult design constraints. The gas stream could be split with separate thermal oxidizers firing a supplemental fuel to provide the temperature required for destruction. It is estimated that about 420 million standard cubic feet of natural gas per year would be needed as a supplemental fuel. However, this would result in emissions of additional pollutants and natural gas is not yet available to the area. Based on the predicted characteristics of the boiler flue gas, the thermal oxidation is identified as not feasible for the project.

The applicant reviewed similar industrial and electric utility biomass boiler projects listed in EPA's RACT/BACT/LAER Clearinghouse database. For the 22 projects listed, VOC emission standards ranged from 0.007 to 2.62 lb/MMBtu. The large range of emission standards are the result of differences in boiler design, operating practices, and fuels. The previous determinations were based on such control technologies identified as good combustion practices, boiler design, and overfire air. Based on a review of previous determinations for biomass boilers and the available control technologies, the applicant recommends the following VOC emission standard as BACT.

VOC $\leq$ 0.06 lb/MMBtu of heat input based on a 3-run test average

The applicant requests the following CO emission standard, which will allow the project to avoid PSD preconstruction review for CO emissions.

CO $\leq$ 0.38 lb/MMBtu of heat input, annual CEMS average

CO and VOC emissions will be minimized by proper boiler design and good combustion practices including: control of combustion air and temperature; even distribution of biomass on fuel grate; and effective control of furnace loads. The above standards would apply when firing bagasse, distillate oil, or a combination of these fuels. Compliance with the VOC standard would be determined by annual performance tests and compliance with the CO standard would be determined by data collected from a continuous emissions monitoring system (CEMS).

CO/VOC - Department's Preliminary Determination

Due to the high combustion temperatures, VOC emissions are predicted to be very low (~ 100 ppmv). This low concentration combined with a high flue gas flow rate (~ 400,000 acfm) makes most add on controls impractical. A review of EPA's RACT/BACT/LAER Clearinghouse database as well as other state databases for similar biomass-fired boilers did not show any cases where add on control technologies were required to reduce CO and VOC emissions from similar biomass-fired boilers. Also, EPA recently proposed Maximum Achievable Control Technology (MACT) standards for industrial boilers. The proposed MACT standards for reducing organic emissions of hazardous air pollutants (HAP) are based on the boiler design with good combustion practices and not add-on control technology. For large solid fuel-fired industrial boilers, this is represented in the proposed regulation by a work practice standard that requires CO emission levels in the boiler flue gas to be maintained at 400 ppmvd @ 3% oxygen or less based on a 24-hour average. Although the proposed MACT standard is not yet applicable to the boiler, the Department has notified the applicant that it would be prudent to design the new boiler for this critical parameter. Due to air infiltration, it is noted that the stack exhaust may contain much higher oxygen levels than the boiler flue exhaust, perhaps 5.5% oxygen in the stack compared to 3% oxygen in the boiler flue exhaust.

The Department reviewed VOC test data for similar modern bagasse-fired boilers. Test data for Clewiston's Boiler 7 shows VOC emissions ranging from 0.001 to 0.114 lb/MMBtu for six stack tests. All but the one test averaged less than 0.02 lb/MMBtu. On the day the tested VOC emission rate was 0.114 lb/MMBtu, the CO emission rate was reported as 0.392 lb/MMBtu, which may indicate that the unit was not operating under the best combustion conditions. Test data was also reviewed for New Hope Power's three 715 MMBtu/hour cogeneration boilers when firing bagasse. The tests indicate VOC emissions ranging from 0.007 to 0.02 lb/MMBtu for nine separate stack tests. This information suggests that actual VOC emissions from a newly designed bagasse-fired boiler will be less than 0.02 lb/MMBtu when adhering to good combustion practices.

In addition to bagasse, the proposed boiler will also fire distillate oil as a startup fuel and supplemental fuel. The firing of distillate oil results in a more efficient fuel combustion process with much lower VOC emissions (~ 0.0014 lb/MMBtu) than the bagasse firing. Based on the available information, the Department makes the following preliminary VOC BACT determination.

VOC $\leq$ 0.05 lb/MMBtu based on a 3-run test average at permitted capacity

The above standard is based on a modern boiler designed for efficient fuel combustion and the use of good combustion practices including the control of combustion air and temperature, even distribution of biomass on fuel grate, and effective control of furnace loads. The standard is twice the emission rate expected from a newly designed modern bagasse-fired boiler. However, it also considers fluctuations in emissions due to varying parameters such as fuel heating value and moisture content. Compliance with the standard will be demonstrated based on initial and annual compliance tests conducted in accordance with EPA Method 25A. EPA Method 18 may also be used to subtract the methane and ethane fraction of total hydrocarbons measured by EPA Method 25A.

For CO emissions, the Department will establish the following standard as a short-term limit with compliance demonstrated by initial and annual stack testing as determined by EPA Method 10.

CO $\leq$ 0.38 lb/MMBtu based on a 3-run test average at permitted capacity under steady-state conditions

This is the standard requested by the applicant, which shows the capability of the boiler to operate with low CO emissions while employing good combustion practices. To provide reasonable assurance that the project remains minor with respect to PSD, the Department will also specify the following CO standard with compliance demonstrated by data collected from a Continuous Emissions Monitoring System (CEMS) for carbon monoxide.

CO $\leq$ 1285.0 tons per consecutive 12 months including startup, shutdown, and malfunction (CEMS)

CO emissions during startups, shutdowns, and malfunctions shall be minimized to the extent possible, but all such emissions shall be included in average used to determine compliance with the above standard. In general, short-term CO emissions during such periods are not expected to exceed 4.5 lb/MMBtu. However, the air quality analysis showed no adverse impacts with a modeled 1-hour maximum emissions rate as high as 6.5 lb/MMBtu.

As indicators of adherence to good combustion practices, the draft permit will identify target ranges for the flue gas oxygen content and CO concentration. The target CO level will be identified as the proposed MACT standard of 400 ppmvd @ 3% oxygen based on a 24-hour average excluding startup and shutdown. As stated in the proposed MACT, "... [EPA] consider[s] monitoring and maintaining CO emission levels to be associated with minimizing emissions of organic HAP. Carbon monoxide is generally an indicator of incomplete combustion because CO will burn to carbon dioxide if adequate oxygen is available. Therefore, controlling CO emissions can be a mechanism for ensuring combustion efficiency and may be viewed as a kind of GCP (good combustion practice)." Therefore, the proposed work practice standard will be used as a general target by the operators to minimize CO, VOC, and organic HAP emissions. Operation outside the proposed oxygen or CO 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 62-210.700, F.A.C.

### Nitrogen Oxides (NOx)

NOx emissions will result from the combustion of bagasse and distillate oil, primarily in the form of thermal NOx. NOx emissions from fuel-bound nitrogen are low because bagasse (~ 0.38% by weight) and distillate oil (~ 0.015% by weight) contain only small amounts of nitrogen. In addition, uncontrolled NOx emissions when firing bagasse are generally lower than other standard solid fuels such as coal due to the lower heating value (3600 Btu/lb, wet) and high moisture content (~ 50%), which results in a lower combustion temperature.

Applicant's NOx Review

The applicant identified the following NOx control technologies: oxidation of NOx with subsequent absorption; selective catalytic reduction (SCR); selective non-catalytic reduction (SNCR); SCONOx™; air staging; fuel staging; steam injection; flue gas re-burn (FGR); natural gas re-burn (NGR); overfire air (OFA); less excess air (LEA); combustion optimization; reduce air preheat; low NOx burners (LNB); and ultra low nitrogen fuels. The proposed boiler design will incorporate overfire air, low excess air, low nitrogen fuels, low-NOx burners for distillate oil firing, and good combustion practices. These control techniques are estimated to result in a NOx emission rate of 0.24 to 0.28 lb/MMBtu heat input without add on controls. This is about 10% to 30% higher than the New Hoper Power cogeneration boilers, which are large modern boilers that started up in 1997 and fire wood and bagasse as the primary fuels. NOx emissions are expected to be higher because Boiler 8 is being designed for high temperatures, improved combustion efficiency, and low CO emissions.

Of the remaining add on control options, several technologies have demonstrated control efficiencies as high as 80% for specific applications. The following discusses the applicant's review of each option for the bagasse-fired boiler project.

- *Oxidation of NOx with Subsequent Absorption*: Oxidants such as ozone, ionized oxygen, or hydrogen peroxide can be injected into the flue gas to oxidize nitrogen to a higher valence state, which makes NOx soluble in water. A gas scrubber can then be used to remove the NOx. A non-thermal plasma reactor can be used to generate gas-phased radicals, which oxidize NOx to form nitric acid. A wet condensing precipitator can then remove the nitric acid. The applicant rejects these technologies as technically infeasible for the project because neither has been demonstrated on large-scale boilers or bagasse combustion.
- *SCONOx™*: This technology is a proven, proprietary, and patented catalytic oxidation and absorption technology, which is recognized by the EPA as "demonstrated in practice" for the control of NOx emissions from combined cycle gas turbines. However, there are only two known applications of this technology, which are both for combined cycle gas turbine projects. The applicant rejects this technology because it has not yet been designed for, or demonstrated on, a biomass-fired boiler.
- *Selective Catalytic Reduction (SCR)*: Within an operating temperature range of approximately 600° F, ammonia could be injected prior to the air preheater. In the presence of a catalyst, ammonia will reduce NOx to nitrogen and water vapor. Although this technology has been successfully employed on coal-fired boilers, the applicant does not believe that this technology has ever been demonstrated on bagasse-fired boilers. The applicant provided supporting information indicating bagasse combustion will result in significant concentrations of several compounds recognized as strong catalyst poisons (sodium, potassium, phosphorous, and chlorides). The following table summarizes potential catalyst poisons found in ash samples taken from Clewiston Boiler 7 and compares to those for a typical coal-fired boiler.

Table 4A. Comparison of Catalyst Poisons in Ash Concentrations, Bagasse vs. Coal Combustion

| Compound | Concentrations Found in Ash Samples, Percent by Weight | | | | | |
|---|---|---|---|---|---|---|
| | Boiler 7 (Bagasse) | Coal | | | | |
| | | Class "F" | Class "C" | hvBb, Utah | hvAb, Penn | hvC |
| $Na_2O$ | 0.3 | 0.1 | 1.9 | 3.8 | 0.4 | 0.6 |
| $K_2O$ | 15.0 | 2.5 | 0.3 | 0.9 | 1.7 | 2.8 |
| $P_2O_5$ | 6.2 | 0.1 | 1.1 | --- | --- | 0.1 |
| $SO_3$ | 9.3 | 0.2 | 2.3 | 6.2 | 1.4 | 4.2 |
| Chlorides | 7.6 | --- | --- | --- | --- | --- |

The applicant also provided the following statement from Halor Topsoe, a catalyst vendor, "We have looked at the data you sent and notice that the content of K in the ash is > 10%, which is twice as much as we observed in a testing on the wood fired boiler. In addition, the content of Cl is > 5%. Thus, a very large amount of KCl aerosols (a severe catalyst poison) is to be expected, which will result in a very rapid deactivation in a high dust position. I will expect that the deactivation will be so high that it is not manageable in practice." In addition, the applicant notes that the SCR catalyst could be plugged and blinded due to the high flue gas moisture content and heavy particulate loading resulting from the high dust configuration. Due to expected premature catalyst deactivation, the applicant believes that placing an SCR system directly after the boiler is inappropriate for this project.

At the request of the Department, the applicant did provide a cost analysis for an SCR system placed after the ESP called a "tail-end" or "low dust" SCR configuration. The analysis included estimated costs to reheat the flue gas to an effective SCR catalyst temperature of about 700° F using distillate oil (natural gas is not yet available in this area). Capital costs were estimated to be $5,233,569 and annualized costs including reheat were estimated at $6,476,474 per year. Assuming an 80% removal rate, the cost effectiveness is estimated at $11,840 per ton of NOx removed. The applicant rejected SCR due to technical concerns regarding catalyst poisons for the high dust SCR configuration and unreasonable costs for the low dust configuration.

- *Selective Non-Catalytic Reduction (SNCR)*: In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. The exhaust temperature must typically be maintained above 1600°F to allow the reaction to occur; otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. Also, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For biomass-fired boilers, SNCR is expected to result in control efficiencies of about 50%. Boiler operating conditions are suitable for the application of SNCR. The applicant provided information indicating that an SNCR system based on urea injection is technically feasible and cost effective.

Based on a review of the available control options, the applicant recommends the following NOx standard based on an SNCR system.

NOx $\leq$ 0.14 lb/MMBtu of heat input based on a 12-month rolling CEMS average excluding startup, shutdown, and malfunction

The applicant believes the long-term NOx standard is warranted for the project due to the variability of bagasse as a fuel, particularly the moisture content.

Department's Preliminary NOx BACT Determination

The Department does not completely accept the applicant's conclusion that SCR is not technically feasible. However, it is recognized that the known worldwide applications of SCR on boilers firing bagasse and wood is very limited, even more so than applications of SCR for refuse-fired plants, for which only non-U.S. applications currently exist. It is also acknowledged that premature catalyst deactivation is a concern given the presence of specific catalyst poisons found in ash generated from bagasse combustion at the existing plant. Finally, based on an estimate of more than $10,000 per ton of NOx removed for a "tail-end system", it does not appear that SCR is cost effective for this project.

EPA's RACT/BACT/LAER Clearinghouse database lists 22 biomass-fired electric utility and industrial boilers with BACT determinations ranging from 0.10 to 0.46 lb/MMBtu. Four of the listed facilities include SNCR systems with NOx standards of 0.10, 0.14, 0.15, and 0.20 lb/MMBtu. It is also noted that the New Hope Power and Palm Bach Power cogeneration plants in Florida fire a combination of wood and bagasse and employ SNCR systems with NOx emission standards equivalent to 0.15 lb/MMBtu based on a 30-day rolling average.

The Department also notes that the New Source Performance Standards in Subpart Da of 40 CFR 60 for electric utility steam generating units establishes a 30-day rolling NOx standard of 0.15 lb/MMBtu for units that are reconstructed or modified after July 9, 1997. In developing this standard, EPA recognized the retrofit capabilities of existing control equipment to comply with such a standard regardless of fuel type. Although the proposed boiler is not subject to the NSPS Subpart Da standard, the critical distinction is that steam generated from Boiler 8 will be used to support milling operations instead of electricity production. The proposed unit will be the largest sugarcane boiler constructed in the United States.

Two preliminary SNCR designs were included as part of the application, both based on urea injection. In general the designs support the following specifications: a maximum NOx reduction level of 50%; an ammonia slip level not to exceed 20 ppmvd @ 7% oxygen; at least three levels of ammonia injectors; control system to automatically adjust the urea injection zones and rates based on the furnace temperature profile, fuels, current urea injection rate, steam load, oxygen and CO levels, and NOx emissions. Both vendors supported a long-term average of 30 days. However, one vendor indicated that a NOx standard of 0.12 lb/MMBtu was achievable on a 24-hour basis.

In general, the urea-based selective non-catalytic reduction (SNCR) system will be designed and installed to reduce nitrogen oxide emissions in the flue gas exhaust by about 50% to achieve the specified emissions standard for nitrogen oxides. The preliminary design consists of the following equipment:

- Urea tank, static mixers, pumps, filters, and controller to blend urea and water for proper concentration;
- Three injection zones (lowest zone is for 50% boiler load and bagasse, middle zone is for maximum boiler load and bagasse, and highest zone is for auxiliary fuel firing);
- Dual-fluid nozzle atomizing injectors to mix urea and atomizing air for injection; and
- A PLC controller that automatically controls the urea injection rate and injector combinations based on the furnace temperature profile (input from infrared monitor), fuels, current urea injection rate, steam load, oxygen levels, carbon monoxide concentration, and NOx emissions.

Urea injection will occur in the boiler exhaust at a point where the flue gas is between approximately 1800° F and 1950° F. A maximum of 45 gph of diluted urea will be injected under maximum load conditions with a minimum design residence time for reaction of 0.5 seconds. The design ammonia slip is less than 20 ppmvd.

The Department agrees that an SNCR system is appropriate for the control of NOx emissions from the proposed bagasse-fired boiler. Based on the available information, the Department makes the following preliminary NOx BACT determination.

| | | |
|---|---|---|
| NOx | ≤ | 0.14 lb/MMBtu based on a 3-run test average conducted at permitted capacity and steady-state conditions |
| | ≤ | 81 ppmvd @ 7% oxygen based on a 30-day rolling CEMS average excluding startup, shutdown, and malfunction |

In addition to the SNCR system, the above standards are based on the proposed boiler design which will incorporate overfire air, low excess air, low nitrogen fuels, low-NOx burners for distillate oil firing, and good combustion practices. The standards apply when firing bagasse, distillate oil, or a combination of these fuels. An initial 3-run test (EPA Method 7E) will be required to demonstrate compliance when operating at permitted capacity, which is expected to result in the highest uncontrolled NOx emissions. Continuous compliance must be demonstrated based on NOx data collected from a Continuous Emissions Monitoring System (CEMS) over 30 successive boiler operating days. The Department believes that 30 operating days will provide more than adequate data to compensate for any fluctuations in emissions due to the varying bagasse characteristics. It is also notes that SNCR vendors typically design systems to achieve emissions standards on a daily basis or even less. To ensure that operation of the SNCR system does not result in excess ammonia emissions, the Department will limit the ammonia slip to 20 ppmvd @ 7% oxygen with compliance demonstrated by initial and annual tests in accordance with EPA Method CTM-027.

The Department will also establish the following additional standard for data that can be excluded from the compliance determination with the above standard due to startups, shutdowns, or malfunctions.

"For the period of excluded data, NOx emissions shall not exceed 162 ppmvd @ 7% oxygen based on a block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction (alternative standard)."

The alternate standard represents the highest expected NOx emissions and covers the periods during which the SNCR system may not be fully operational.

**Particulate Matter ($PM/PM_{10}$)**

Total particulate matter (PM) and particulate matter less than 10 microns in diameter ($PM_{10}$) will be emitted from the proposed boiler due to the ash contents and incomplete combustion of bagasse and distillate oil. The ash content of bagasse ranges from about 2.6% to about 5.3% by weight on a dry basis. The ash content of distillate oil is about 0.06%. Proven control technologies are available for removing particulate matter from the flue gas exhaust of boilers.

Applicant's $PM/PM_{10}$ Review

The applicant identified fuel substitutions, pretreatment devices, electrostatic precipitators (ESPs), fabric filters, and wet scrubbers as available add on equipment for the control of particulate matter. Fabric filters and ESPs were described as having control technologies exceeding 99%. The next highest ranked technology was wet scrubbing with estimated control efficiencies approaching 95%. The applicant identified fabric filters as not feasible for the proposed boiler due to the potential for:

- Plugging, blinding, and frequent bag replacement due to high flue gas moisture and "sticky" particles;
- Bag damage and frequent replacement resulting from high flue gas temperatures; and
- Potential for fire and explosion hazards.

A review of EPA's RACT/BACT/LAER Clearinghouse database shows about 20 similar industrial and electric utility biomass boiler projects. These projects established PM BACT standards based on ESPs, wet scrubbers, multi-cyclones, and fabric filters. The PM emission standards ranged from 0.02 to 0.30 lb/MMBtu. The large range of emission standards are the result of differences in boiler design, fuel types, and operation. Based on a review of previous determinations and available control technologies, the applicant proposed to install a wet cyclone pre-treatment device followed by a dry, negative corona plate ESP. The applicant recommends the following PM emission standard as BACT.

PM $\leq$ 0.026 lb/MMBtu of heat input based on 3-run test average

Opacity $\leq$ 20% based on a 6-minute average except for up to 27% for one 6-minute period per hour

The recommended PM standard represents an overall control efficiency of approximately 99% and is equivalent to the industrial boiler MACT recently proposed by EPA. The opacity limit is equivalent to NSPS Subpart Db standard. The applicant requested an alternate sampling procedure in lieu of the federal NSPS Subpart Db requirement to install a continuous opacity monitoring system (COMS). The request includes additional visible emissions observations when firing distillate oil as well as monitoring the total secondary power input to the ESP as a measure of effective performance. EPA Region 4 previously approved a similar plan for U.S. Sugar's Boiler 7. The Department expects EPA Region 4 to approve the requested Alternate Sampling Procedure for purposes of compliance with the NSPS Subpart Db provisions.

Department's Preliminary $PM/PM_{10}$ BACT Determination

The Department also recognizes ESPs and fabric filters as the top-ranked control options for the removal of particulate matter. The applicant estimated the cost effectiveness of the wet cyclone collector/ESP combination at $118 per ton or particulate matter removed, which is well within the Department's cost considerations. The Department disagrees that fabric filters are not feasible for bagasse-fired boilers; however, it acknowledges the potential for fire problems due to the fly ash characteristics and plugging or blinding due to the high moisture levels of the flue gas. The proposed wet cyclone collector/ESP combination has been proven capable of achieving emission levels comparable to a fabric filter. Based on stack tests conducted on U.S. Sugar's Boiler 7 over the last several years, the average particulate matter emission rate is 0.013 lb/MMBtu (~ 0.007 grains/dscf). This is half of the proposed standard and within the range expected for control by a fabric filter.

A pre-control device will be designed and installed to remove entrained sand and large particles upstream of the electrostatic precipitator. The purpose of the pre-control device is to prevent excessive equipment wear and overloading of the ESP. The preliminary design locates two wet cyclone collectors in parallel before the induced draft fan. Each wet cyclone collector is expected to consist of a large steel vessel with a venturi throat located at the bottom for the inlet flue gas. A series of spray nozzles will be located in the venturi throat to supply a total of about 200-250 gpm of water for each unit. Water is used to wash the large particles away from the sides of the collector down to the discharge hopper. At an approximate flue gas flow rate of 191,000 acfm, the pressure drop across each collector is expected to be approximately 4 inches of water (gage). Flue gas will exit the top of the unit, which will also incorporate an emergency outlet should the normal outlet become plugged. The wet cyclone collectors are expected to remove approximately 50% of the inlet particulate matter, which is dependent on particle size.

The following specifications summarize the preliminary design of the proposed new ESP.

- *Performance*: The proposed ESP will be designed for a collection efficiency of more than 97.00%, a maximum controlled particulate emission rate of 0.026 lb/MMBtu, and a maximum stack opacity of 10%. EPA's AP-42 document estimates uncontrolled particulate matter emissions from firing bagasse of 15.6 lb/ton (~ 2.7 lb/MMBtu). A control efficiency of 99% or more is necessary to achieve the design outlet loading of 0.026 lb/MMBtu. Assuming 50% control by the wet cyclone (1.35 lb/MMBtu), a control efficiency of 98% or more is required to achieve the design outlet loading of 0.026 lb/MMBtu.

- *Specific Collection Area (SCA)*: The specific collection area is the ratio of the total collection surface area to the flue gas exhaust rate and is a rough indicator of the overall efficiency. The preliminary design has a total collection plate area in the range of 91,665 to 144,550 $ft^2$ based on a volumetric flow rate of about 400,000 $ft^3$/minute. This will place the SCA in the range of about 215 to 340 $ft^2$ per 1000 $ft^3$/minute, which falls within the optimum SCA range for fly ash precipitators (200 to 400 $ft^2$ per 1000 $ft^3$/minute). [3]

- *Aspect Ratio (L/H)*: The aspect ratio is ratio of the effective length of the ESP over the effective height of the ESP. If the aspect ration is small (< 1.0), then there is a greater chance that particulate matter will be re-entrained during periods of rapping and carried out of the ESP before reaching the hoppers. For the proposed ESP design, the effective field length is estimated between 36.4 and 40.8 feet and the effective field height is estimated at 36 feet. Therefore, the aspect ration will be in the range of 1.01 to 1.36, which falls with the expected range of aspect ratios (1.0 to 1.5) for ash precipitators with high collection efficiencies. [3]

- *Particle Migration Velocity (w)*: Particle migration velocity represents the *collectability* of a particle based on the design of a specific ESP. The critical design parameter for an ESP is the collection efficiency, which is a function of the plate collection area, the volumetric flow rate, and the particle migration velocity. The following simplified equation shows the general relationship of these parameters. [3]

  $Ac = - Q / w [ \ln ( 1 - n) ]$, where:

  Ac is the plate collection area, $ft^2$ (assume 91,665 to 144,550 $ft^2$)
  Q is the volumetric flow rate, $ft^3$/min (assume 400,000 acfm)
  w is the particle migration velocity, ft/sec
  $n$ is the collection efficiency, decimal form, (assume 0.97)

  Rearranging the equation would be:

  $w = - (Q\ ft^3/min) / (118{,}108\ ft^2) [ \ln (1 - 0.97) ] (min/60\ sec) = 0.20\ ft/sec$

  Based on the above equation and the preliminary design, a rough estimate of the particle migration velocity is between 0.16 to 0.26 ft/second, which falls within the expected range of particle migration velocities (0.1 to 0.5 ft/sec) for fly ash precipitators.[1, 3]

- *Plate Area / Electrical Transformer-Rectifier (T-R) Set*: In most cases, more electrical bus sections (T-R sets) means a higher probability of continually achieving the designed collection efficiency. A general rule-of-thumb for fly ash precipitators is to have one T-R set for every 10,000 to 30,000 $ft^2$ of collection plate area.[1, 3] Based on preliminary information, the design should have between 4 and 9 TR-sets for a design collection area of 91,665 $ft^2$ and between 5 and 14 T-R sets for a design collection area of 144,550 $ft^2$. Total power consumption is expected to range from 231-303 kW.

After review of the available information, the Department establishes the following preliminary BACT standard for particulate matter based on the proposed wet cyclone/ESP design.

PM $\leq$ 0.026 lb/MMBtu of heat input based on a 3-run test average (EPA Method 5) at permitted capacity

Opacity $\leq$ 20% based on a 6-minute average (EPA Method 9)

The above PM standard is equivalent to the industrial boiler MACT standard that was recently proposed by EPA as achievable for solid fuel fired boilers. It is equivalent to approximately 0.014 grains per dry standard cubic feet of flue gas, which approaches the level of control offered by a baghouse. There appears to be little benefit in establishing a very low opacity limit for the new unit, which will be located adjacent to existing boilers with wet scrubbers, condensing water vapor plumes, and opacity limits as high as 30% to 40%. The above opacity standard does not allow the exceptional period granted by NSPS Subpart Db. A properly functioning ESP will be able to comply with 20% opacity at all times. During startup and shutdown, the Department will establish the following opacity standard.

Opacity $\leq$ 20% based on a 6-minute average except for up to 27% for one 6-minute period per hour (EPA Method 9)

In general, this standard will apply for two cases: during an initial startup when the boiler is firing only distillate oil; and during shutdown when bagasse is no longer being fired and the ESP is taken off line because combustion on the grate is substantially complete. Because EPA Region 4 has not yet approved the Alternate Sampling Procedure for opacity, draft permit will include the NSPS Subpart Db requirement for a COMS. However, the permit allows the uses of the Alternate Sampling Procedure in lieu of a COMS if later approved by EPA Region 4. The permit also includes a plan to test and establish a minimum total secondary power input level for the ESP, which represents effective performance.

**Sulfuric Acid Mist (SAM) and Sulfur Dioxide ($SO_2$)**

These pollutants will be emitted due to the available sulfur in the bagasse and distillate oil being fired. Bagasse typically contains 0.03% to 0.07% by weight on a dry basis and the proposed distillate oil will contain no more than 0.05% sulfur by weight. For fuel oil firing, nearly all of the fuel sulfur is converted to $SO_2$ and possibly some SAM. However, the sugar industry has test data for bagasse combustion showing actual $SO_2$ emissions that are much lower than the amount predicted by simple stoichiometry. It is believed much of the $SO_2$ formed is adsorbed onto the alkaline fly ash particles that are generated during bagasse combustion.

Applicant's SAM and $SO_2$ Review

The applicant identified sorbent injection (~ 50-80% reduction), wet scrubbing (> 90% reduction), dry scrubbing (> 90% reduction), spray dryer scrubbing (~ 90-95% reduction), and regenerative flue gas desulfurization systems with recovery of sulfur or sulfuric acid (> 95% removal) as feasible controls for the removal of $SO_2$ emissions. The applicant states that the levels of control are similar and that spray dryer scrubbers are generally less expensive than the other methods. Two cost quotes were obtained for a lime spray dryer absorber with pulse jet baghouse and ancillary equipment. Estimated total capital costs ranged from about $12 to $15 million. Annual operating and maintenance costs ranged from about $780,000 to $900,000. Based on a 90% reduction, the cost effectiveness ranged from $5500 to $7700 per ton of $SO_2$, HF, and HCl emissions removed. The applicant believes that these costs are unreasonable for this project. Costs for other add on controls are expected to be much higher and also not cost effective.

A review of EPA's RACT/BACT/LAER Clearinghouse database shows 15 similar industrial and electric utility biomass boiler projects. These projects established $SO_2$ BACT standards ranging from 0.016 to 0.54 lb/MMBtu. Two projects required wet scrubbers, one project required a spray dryer absorber, and the remaining projects relied on low sulfur fuels. The following table lists the standards for the projects with controls.

Table 4B. Recent BACT Determinations for Biomass Boilers Requiring Add-On Controls

| RBLC ID | State | Project | Permit Date | Capacity MMBtu/hr | Standard lb/MMBtu | Control / Fuel |
|---|---|---|---|---|---|---|
| ME-0021 | ME | S.D. Warren Co., Boiler 2 | 11/27/01 | 1300 | 0.27 | Wet Scrubber / Wood |
| AL-0112 | AL | Champion International | 12/09/97 | 710 | 0.045 | Wet Scrubber / Wood |
| FL-0198 | FL | Wheelabrator Ridge Energy | 0929/92 | 630 | 0.1 | SDA / Wood/RDF |

The S.D. Warren project is a paper mill power boiler that fires bark, wood, sludge, No. 6 fuel oil, tire-derived fuel, and waste oil. Similarly, the Champion International project is paper mill power boiler that fires wood, paper, effluent treatment solids, tire-derived fuel, natural gas, and non-condensable gases. The Wheelabrator Ridge Energy project is a waste-to-energy boiler that fires wood, tire-derived fuels, and refuse. Due to the high-sulfur fuels being fired at each plant, the uncontrolled $SO_2$ emissions would be much higher than emissions from the proposed project, which would make add-on controls appear more cost effective. However, the standards for the S.D. Warren and the Wheelabrator Ridge Energy projects are still higher than predicted emissions from the proposed project. The standard for the Champion International project is about 25% lower than the maximum predicted for the proposed project. Based on the use of low sulfur fuels, the applicant recommends the following $SO_2$ standards as BACT.

$SO_2$ $\leq$ 0.06 lb/MMBtu of heat input for bagasse firing, 3-run test average

Fuel sulfur $\leq$ 0.05% sulfur by weight for distillate oil

Due to the predicted low levels of sulfuric acid mist emissions, the $SO_2$ standards and distillate oil sulfur specification will serve as surrogate standards that effectively limit potential emissions of this pollutant.

Department's Preliminary $SO_2$ BACT Determination

The Department believes that the applicant's estimated cost effectiveness of $5500 to $7700 per ton of acid gases removed may be at the high end of consideration. However, based on CEMS data collected in 2000 for the similar New Hope Power cogeneration boilers, the annual $SO_2$ emission rate is approximately 0.03 lb/MMBtu when firing a combination of wood and bagasse. Wood typically has a higher sulfur content than bagasse and generally results in higher $SO_2$ emissions. Therefore, this long-term average should be a conservative factor for estimating annual $SO_2$ emissions from Boiler 8. Basing the annual emission reductions on this factor increases the cost effectiveness of a spray dryer absorber to more than $10,000 per ton. This is clearly not cost effective. In addition, the purchased equipment cost is about $6.5 million for the spray dryer absorber, which is nearly 45% of the estimated purchased equipment cost of the new boiler (~ $15 million). Therefore, the Department rejects add on flue gas desulfurization as not cost effective for this project.

Based on a review of the available information, the Department makes a preliminary determination that the following $SO_2$ emission standards represent BACT based on low sulfur fuels.

$SO_2$ $\leq$ 0.06 lb/MMBtu of heat input for bagasse firing based on a 3-run stack test at permitted capacity

Fuel sulfur $\leq$ 0.05% sulfur by weight for distillate oil

The above distillate oil sulfur specification has been frequently established as the BACT standard for modern gas turbine projects. This is equivalent to 0.051 lb/MMBtu, which is nearly comparable to the standard for bagasse. Although the actual $SO_2$ emissions when firing bagasse are expected to be less than 0.03 lb/MMBtu, bagasse may vary significantly from sample to sample. Therefore, the applicant's requested standard of 0.06 lb/MMBtu is considered reasonable as compliance will be based on an annual 3-run stack test (EPA Method 6C). The draft permit will also include requirements to periodically sample and analyze the bagasse for the fuel sulfur content. Due to the predicted low levels of sulfuric acid mist emissions, the $SO_2$ standard and distillate oil sulfur specification will serve as surrogate standards that effectively limit potential emissions of this pollutant.

**Lead, Mercury, and Fluorides**

The potential net emission increases of lead, mercury, and fluorides are predicted to be less than half of the corresponding PSD significant emission rates. These estimates are based on emission factors that are believed to be very conservative for bagasse-fired boilers. In addition, the wet cyclone collector/ESP combination is expected to be very effective in the removal of particulate forms of these contaminants. Therefore, similar to the proposed MACT standard, no specific standards are established. However, the low particulate matter emission standard serves as a surrogate for the overall control of these pollutants.

## 5. BAGASSE HANDLING SYSTEM, CONTROL TECHNOLOGY REVIEW

Due to this project, emissions increases of CO, NOx, PM, SAM, $SO_2$, and VOC will result from small miscellaneous sources in the refinery and from bagasse handling system. However, the emissions increases for CO, NOx, SAM, $SO_2$, and VOC are generally less than 1% of the overall potential emissions from the project sources and not considered substantial. Therefore, the Department determines that these activities will continue to be regulated by current permits. However, PM emission increases from the bagasse handling system (~ 18.5 tons per year) represent approximately 15% of the overall potential emissions from the project sources. Therefore, the Department will establish BACT standards for these activities.

U.S. Sugar proposes the following changes to the existing bagasse conveyor system accommodate Boiler 8: expand conveyor belt C4; add a new conveyor belt to feed bagasse to Boiler 8; and increase the bagasse throughput of the handling system. The proposed changes also involve installing only 5 of the 6 previously proposed dust collectors for the bagasse handling system and eliminate transfer belt conveyor No. 2 (Application Nos. 0510003-011-AC and 0510003-015-AC). The combined flow rates of the dust collectors will be 18,475 acfm. The collection efficiency of the dust collectors is estimated to be 99.99% for particles greater than 4 microns in diameter. The following table summarizes the revised dust collector system:

Table 5A. Bagasse Conveyor Dust Collection System

| Dust Collector | Manufacturer | Model No. | Flow Rate acfm | Outlet grains/afc | ~ 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 |

The applicant recommends enclosing bagasse conveyors, installing dust collectors on the conveyor transfer points, and a work practice standard of 5% opacity for each of the dust collector outlets. Based on a review of the available information, the Department makes a preliminary determination that the following work practice standards represent BACT for controlling particulate matter emissions from the bagasse handling system.

- Enclose bagasse conveyors;
- Install dust collectors on the conveyor transfer points;
- Opacity from the dust collector outlets shall not exceed 5% opacity

Initial and annual compliance with the opacity standard will be determined by EPA Method 9.

## 6. COMMENTS ON THE APPLICATION

### Comments from the National Park Service

The National Park Service (NPS) indicated that it did not anticipate that the proposed project will have a significant impact on the Everglades National Park. However, NPS offered the following comments on the Best Available Control Technology (BACT) analysis presented in the application.

1. Particulate Matter: U.S. Sugar proposes an electrostatic precipitator (ESP) at an emission rate of 0.026 lb/MMBtu. We agree with the choice of an ESP and with the proposed emission rate.

   *Department's Response*: The draft permit reflects this level of control.

2. Nitrogen Oxides: U.S. Sugar concluded that over-fire air and "good combustion practices" represent BACT at an average emission rate of 0.22 lb/MMBtu. In its 1999 application to increase the permitted operating hours of its bagasse and #6 oil-fired Boiler #4, U.S. Sugar concluded that "good combustion practices" represent BACT because they were achieving an average emission rate of 0.08 lb/MMBtu. We believe that a new boiler should be able to control $NO_x$ emissions to levels no greater than demonstrated by Boiler #4 burning the same fuel (i.e., 0.08 lb/MMBtu).

   U.S. Sugar rejected Selective Non-catalytic Reduction (SNCR) based upon a cost-effectiveness of $1400 per ton of $NO_x$ removed. We suggest that $1400/ton may be economically feasible on the basis that many states use a cost-effectiveness threshold of $2000-$5000/ton for $NO_x$.

   *Department's Response*: The proposed unit will be a newly designed, modern spreader stoker boiler. As such, the operating temperatures, combustions efficiency, and NOx emissions are expected to be much higher than Boiler 4, which is a refurbished power plant boiler originally constructed prior to 1970. The less efficient combustion design of Boiler 4 leads to much higher emissions of carbon monoxide and organic compounds. The proposed design is expected to result in uncontrolled NOx emissions as high as 0.28 lb/MMBtu. For this reason, the Department's preliminary BACT determination is a NO emission rate of 0.14 lb/MMBtu based on the installation of SNCR.

3. Sulfur Dioxide: U.S. Sugar proposed firing of 0.05% sulfur fuel oil as BACT. By 2006, the Environmental Protection Agency (EPA) will require that 80% of all on-road diesel fuel meet a sulfur limit of 0.01%, and by 2010, 100% of all on-road diesel fuel must meet that limit. Although those EPA limits will not directly apply to fuel oil burned in a boiler such as that proposed by U.S. Sugar, it is clear that 0.01% sulfur oil will be readily available by 2006. We are aware of at least four proposed combustion turbine projects in Virginia (Tenaska-Bear Garden, Tenaska-Fluvanna Co., Dynegy-Chickahominy Power, and ODEC-Louisa Co.) and one facility in Georgia (Southern Co.-Macintosh) that have proposed the use of fuel oil limited to 0.01% sulfur. U.S. Sugar should address the feasibility of using such a lower sulfur fuel oil in its BACT analysis. We request U.S. Sugar be required to purchase and use 0.01% sulfur oil no later than 2006.

   *Department's Response*: In making the BACT determination, the Department relied on information available at the time of the application review. Although there are proposals to lower the fuel sulfur as described, it does not seem appropriate to base the BACT determination for a supplemental fuel on *proposed* fuel sulfur levels and implementation dates. At full permitted capacity, the difference in the fuel sulfur limits would result in a maximum potential decrease of less than 20 tons per year. The Department's BACT determination includes a fuel sulfur specification of 0.05% sulfur by weight or less.

## 7. AIR QUALITY ANALYSIS REVIEW

### Introduction

The proposed Boiler 8 project will result in net annual emissions increases that exceed the PSD significant emission rates for nitrogen oxides (NOx), particulate matter ($PM_{10}$), sulfuric acid mist (SAM), sulfur dioxide ($SO_2$), and volatile organic compounds (VOC). NOx, $PM_{10}$, and $SO_2$ are all criteria pollutants with defined significant impact levels, PSD increments, state and federal ambient air quality standards (AAQS), and de minimis preconstruction monitoring concentrations. SAM is a non-criteria pollutant with no defined significant impact levels, PSD increments, AAQS, or de minimis preconstruction monitoring concentrations. Therefore, no air quality impact analysis is required for SAM. VOC is a precursor for ozone, which is a criteria pollutant. For VOC, there are no applicable significant impact levels, PSD increments, or AAQS. However, projects with net increases of more than 100 tons per year of VOC require an ambient impact analysis. Due to the shutdown of Boiler 3, net emissions increases of carbon monoxide (CO) are below the PSD significant emission rate and the project nets out of PSD preconstruction review for this pollutant. In summary, the air quality impact analyses required by the PSD regulations for this project include:

- An analysis of existing air quality for $PM_{10}$, $SO_2$, and VOC;
- A significant impact analysis for $NO_2$, $PM_{10}$, $SO_2$, and VOC;
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The analyses for significant impacts, PSD increments, and AAQS depend on air quality dispersion modeling carried out in accordance with EPA and Department guidelines. The analysis of growth-related impacts to air quality generally focuses on a qualitative review of residential, commercial, and industrial growth in the vicinity of the project.

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. However, the following EPA-directed stack height language is included: "In approving this permit, 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." A discussion of the required analyses follows.

**Analysis of Existing Air Quality**

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied by existing representative monitoring data, if available. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration.

If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. The background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year.

The following table shows maximum predicted air quality impacts from the project compared to the de minimis preconstruction ambient air quality monitoring levels.

Table 7A. Predicted Maximum Air Quality Impacts from the Project Compared to the De Minimis Levels

| Pollutant | Averaging Time | Maximum Predicted Impact ($\mu g/m^3$) | Impact Greater than De Minimis? | De Minimis Level ($\mu g/m^3$) |
|---|---|---|---|---|
| $SO_2$ | 24-hr | 2.3 | No | 13 |
| $PM_{10}$ | 24-hr | 4.9 | No | 10 |
| $NO_2$ | Annual | 0.5 | No | 14 |
| VOC | Annual | 168 (133) tons/year* | Yes | 100 tons/year |

* The net annual VOC emissions increases for the project are: 168 tons/year based on the application and 133 tons/year based on the preliminary BACT determination.

With the exception of VOC, all pollutants are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required. Because VOC impacts from the project are predicted to be greater than the de minimis level, the applicant is not exempt by rule from preconstruction monitoring for this pollutant. However, the applicant may satisfy the preconstruction monitoring requirement by using previously existing representative data. There are no ambient monitors located in Hendry County, which remains a relatively rural area as discussed in the Additional Impacts Analysis. However, conservatively representative data is available for the more urbanized adjacent Palm Beach County located east of the project. Existing monitoring data shows the area to be in attainment with the ozone standard. No background concentrations were established because there were no predicted significant impacts for any pollutants, which will be shown in the following section.

**Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses**

PSD Class II Area Model

Typically, the EPA-approved Industrial Source Complex Short Term (ISCST3) model is used in the significant impact modeling analysis. However, for a previous project (Permit No. PSD-FL-272), EPA Region 4 approved the use of a modified version of the program that included Plume RIse Model Enhancements (ISC-PRIME). The applicant successfully argued that the ISC-PRIME model was better suited for handling the complex building downwash scenarios at the Clewiston sugar mill and refinery. Once the ISC-PRIME model is approved for a given facility, it is EPA's policy that the alternate model be used on all subsequent projects for purposes of consistency. Therefore, the applicant performed the required air dispersion modeling to demonstrate compliance with the ambient air quality standards and PSD increments using the previously approved ISC-PRIME model.

The ISC-PRIME model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISC-PRIME model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISC-PRIME model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida. The 5-year period of meteorological data was from 1987 through 1991. This NWS station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Because five years of data are used in ISC-PRIME, 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 there are significant impacts occur from the project on 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.

PSD Class I Area Model

Since the PSD Class I CNWA 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, regional haze and maximum sulfur and nitrogen deposition in the Everglades National Park. 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. For this project, the CALPUFF analysis used MM4/MM5 data from 1990, 1992 and 1996 to initialize the CALMET wind field. The CALMET model produced a modeling domain extending 470 km in the north-south direction by 450 km in the east-west direction. The modeling domain was produced by using meteorological data from 3 upper air, 8 surface, and 23 precipitation stations located throughout the state of Florida.

**Significant Impact Analysis**

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 500 receptors were placed along the facility's restricted property line and out to 25 km from the facility, which is located in a PSD Class II area. Modeling refinements were done, as needed, by using a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of one or two degrees. 126 receptors were placed in the Everglades National Park (ENP) PSD Class I area located 102 km away at its closest point. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in the vicinity of the facility or in the Class I areas. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of the modeling for significant impacts, including the radius of significant impact, if applicable.

Table 7B. Maximum Predicted Project Impacts in the Vicinity of the Facility Compared to the PSD Class II Significant Impact Levels

| Pollutant | Averaging Time | Maximum Predicted Impact ($\mu g/m^3$) | Significant Impact Level ($\mu g/m^3$) | Significant Impact? (Yes/No) | Radius of Significant Impact (km) |
|---|---|---|---|---|---|
| $SO_2$ | Annual | 0.1 | 1 | No | -- |
| | 24-hr | 2.3 | 5 | No | -- |
| | 3-hr | 14.6 | 25 | No | -- |
| $PM_{10}$ | Annual | 0.97 | 1 | No | -- |
| | 24-hr | 4.9 | 5 | No | -- |
| $NO_2$ | Annual | 0.5 | 1 | No | -- |

Table 7C. Maximum Predicted Project Impacts in the Everglades National Park (ENP) Compared To the PSD Class I Significant Impact Levels

| Pollutant | Averaging Time | Maximum Predicted Impact ($\mu g/m^3$) | Significant Impact Level ($\mu g/m^3$) | Significant Impact? (Yes/No) |
|---|---|---|---|---|
| $SO_2$ | Annual | 0.003 | 0.1 | No |
| | 24-hr | 0.11 | 0.2 | No |
| | 3-hr | 0.75 | 1.0 | No |
| $PM_{10}$ | Annual | 0.001 | 0.2 | No |
| | 24-hr | 0.01 | 0.3 | No |
| $NO_2$ | Annual | 0.004 | 0.1 | No |

As shown in the above tables, the maximum predicted air quality impacts due to all pollutants are less than the PSD significant impact levels in the vicinity of the facility and in the Everglades National Park (ENP); therefore, no further modeling was required.

Discussion of VOC Emission Impacts

Ozone is a criteria pollutant and the prime ingredient in urban "smog". It is not directly emitted from stationary sources, but is formed at ground level through a series of complex chemical reactions involving emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC) in the presence of sunlight. For this reason, VOC emissions are regulated as a precursor for the criteria pollutant ozone. As previously mentioned, potential VOC emissions increases are above the de minimis level of 100 tons per year, which requires an ambient impact analysis and a gathering of ambient ozone concentrations.

Impacts of VOC emissions on ambient ozone levels are not usually realized locally, but contribute to the regional formation of ozone. However, the main impact on ozone from stationary sources in the area is likely due to NOx rather than VOC emissions. Furthermore, ozone formation occurs on a regional basis and includes the contributions of emissions from such as motor vehicle traffic, large power plants, and numerous miscellaneous VOC sources throughout the region. In general, it is found that motor vehicles contribute the majority of VOC emissions in urban areas having adverse ambient ozone levels.

Based on information in Florida's Air Resource Management System database, existing stationary sources in Hendry County accounted for 3148 tons per year of VOC emissions in 2002. The maximum net VOC emissions increase from the project would be 133 tons per year, which represents only a 4% increase in stationary source VOC emissions. This is still a relatively small contribution towards regional ozone formation. It is further noted that actual VOC emissions from the proposed Boiler 8 are expected to be about half of the maximum permitted levels, which would bring the net VOC emissions increases below the 100 ton per year de minimis level.

As shown in the Additional Impacts Analysis, Hendry County is a lightly populated rural area. As such, ambient ozone levels are predicted to be low and no monitoring network has been established. However, representative data is available for the more urbanized Palm Beach County located east of the project, which offers a conservative estimate for Hendry County. Data from this regional ozone monitoring system would satisfy any pre-construction monitoring requirements as well as provide a conservative estimate of background ozone levels. The existing regional ozone monitoring data shows the area to be in attainment with the ozone standards.

The applicant presented the potential VOC emissions increases to the Department and discussed available options to predict potential impacts associated with the emissions and formation of ozone. However, there are no approved stationary point source models available for use in predicting ozone impacts. Actual annual VOC emissions from the proposed Boiler 8 are expected to be less than 100 tons per year based on predicted operational levels. Ambient ozone monitoring data collected by the regional monitoring system over the last several years show attainment with the current ozone standards and predicts attainment with the proposed new ozone standards. Based on the available information, the Department determines that the use of a complex regional model incorporating the intricate chemical mechanisms for predicting ozone formation is not suitable for this project, nor would it be sensitive enough to evaluate impacts associated with the changes in ambient ozone levels due to this project. Therefore, no further analysis is required.

**Additional Impacts Analysis**

Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to $PM_{10}$, $SO_2$, NOx and CO emissions as a result of the proposed project, including all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected. A regional haze analysis using the long range transport model CALPUFF was done for the ENP Class I area. This analysis showed no significant impact on visibility in this area. The maximum predicted sulfur and nitrogen deposition on the Everglades National Park from this project was below the Federal Land Manager criteria.

Growth-Related Air Quality Impacts

Hendry County is located south of Lake Okeechobee and west of Palm Beach County. Consisting of approximately 1163 square miles, it is the 8th largest county based on land area. However, Hendry County accounts for only 37,000 of the 16 million Florida residents. In contrast, the adjacent and more urbanized Palm Beach County has approximately 1.2 million residents. Hence, Hendry County may be described as a lightly populated rural area. [Population information is based on 2001 data from the U.S. Census Bureau.]

The applicant provided the following information on trends (1977 to 2000) for Hendry County based on data from the "Florida Statistical Abstract".

- *Population*: The population increased by about 19,300 (~ 114% increase).
- *Retail Trade*: Approximately 29 retail trade establishments were added (~ 28% increase).
- *Labor*: About 6265 people were added to the available work force (~ 87% increase).
- *Tourism*: Hotels and motels increased available capacity by about 49%.
- *Transportation*: The estimated vehicle miles traveled (VMT) on major roadways increased by 280,000 VMT (~ 86% increase).
- *Power Plants*: There are no power plants in Hendry County.
- *Manufacturing*: Industry showed a 25% increase in the number of employees.

- *Agriculture*: Agricultural industries showed a 91% increase in the number of employees. The largest nearby newly constructed stationary source is the Southern Gardens Citrus Processing Corporation.

This information suggests that Hendry County has experienced only modest growth since 1977. During the expected two years of construction, the project is expected to require about 25 additional workers. After completion of the project, no additional operational workers will be required. Based on this information, there will be negligible air quality impacts from any growth associated with the project.

## 8. 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. Cleve Holladay is the project meteorologist responsible for reviewing the air quality modeling analysis. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. 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-333 Boiler 8 - TEPD}*

# 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-333 |
| Project No. 0510003-021-AC |
| Facility ID No. 0510003 |
| SIC Nos. 2061, 2062 |
| Permit Expires: December 31, 2006 |

**FACILITY AND LOCATION**

The United States Sugar Corporation operates the existing Clewiston sugar mill and refinery, 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 passed through 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**

This permit authorizes the construction of Boiler 8 (EU-028), a new bagasse-fired boiler with a maximum heat input rate of 1030 MMBtu/hour. The 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**



(DRAFT)

Michael G. Cooke, Director
Division of Air Resources Management

Effective Date

## PROJECT DESCRIPTION

The United States Sugar Corporation proposes to construct Boiler 8 (EU-028), which will fire bagasse as the primary 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. Bagasse and distillate oil ($\leq 0.05\%$ sulfur by weight) will be used to minimize the potential for 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 bagasse handling system (EU-027), bagasse conveyors will be enclosed and dust collectors installed on the conveyor transfer points. The project will also potentially cause small increases in actual annual emissions from miscellaneous existing activities in the refinery.

## REGULATORY CLASSIFICATION

Title III: The existing facility is a potential 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 source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The existing facility operates units subject to the New Source Performance Standards of 40 CFR 60.

## 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 Requirements

Appendix E. Final BACT Determinations

Appendix F. Good Combustion and Operating Practices

Appendix G. Quarterly CO and NOx Emissions Report

## RELEVANT DOCUMENTS

The permit application and additional information received to make it complete are not a part of this permit; however, the information is specifically related to this permitting action and is 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. All documents related to applications for permits to construct minor sources of air pollution or to operate the facility shall be submitted to the Department's South District Office at 2295 Victoria Avenue, Suite 364, Fort Myers, Florida, 33901-3381.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's South District Office at the above address.

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(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.]

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 the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's South District Office with a copy to the Department's New Source Review Section in the Bureau of Air Regulation. [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.<br>*Fuels*: The primary fuel will be bagasse (SCC No. 1-02-011-01). Distillate oil (SCC No. 1-02-005-01) containing less than 0.05% sulfur by weight will be fired as a restricted alternate fuel for startup and supplemental uses.<br>*Capacity*: The maximum continuous steam production 500,000 pounds per hour based on a maximum heat input rate of 936 MMBtu per hour (24-hour averages).<br>*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 minimize the potential for emissions of sulfuric acid mist and sulfur dioxide.<br>*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° F and a volumetric flow rate of 400,000 acfm at 5.5% oxygen (225,000 dscfm at 7% oxygen).<br>*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 nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), sulfur dioxide ($SO_2$), 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); and the federal New Source Performance Standards (NSPS) in Subpart Db (industrial boilers) of 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C. See Appendices C and D of this permit for these applicable requirements.}*

## EQUIPMENT

1. Shutdown of Boiler 3: Boiler 3 shall be permanently shutdown prior to operation of Boiler 8. In no case, shall Boilers 3 and 8 operate concurrently. No later than 30 days after first firing bagasse in Boiler 8, the permittee shall submit written notice to the Compliance Authority confirming first fire in Boiler 8 and the permanent shutdown of Boiler 3. *{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.}* [Design; Rule 62-212.400(2)(e) and (g), 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 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 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. Rotating feeders,

pneumatic spreaders, a traveling grate, and overfire air will be used to fire the primary fuel of bagasse. 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 two wet cyclone collectors 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 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. The combinations of urea injection rates and zones will be determined based on 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(5)(c), F.A.C.]

**PERFORMANCE REQUIREMENTS**

4. Authorized Fuels: Boiler 8 shall fire bagasse as the primary 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. [Design; Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C.]

5. Boiler Capacities and Restrictions: The maximum continuous steam production capacity (24-hour average) is 500,000 pounds per hour based on a maximum heat input rate of 936 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 pounds of steam per day (equivalent to 500,000 pounds of steam per hour and 936 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).

   The hours of operation are not restricted (8760 hours/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; Applicant Request; Rules 62-4.070(3), 62-212.400(2)(g), 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(5)(c), 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, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. 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(5)(c), F.A.C.]

   b. Carbon Monoxide (CO): As determined by EPA Method 10 stack test, CO emissions shall not exceed 0.38 lb/MMBtu and 355.7 pounds per hour. [Rules 62-4.070(3) and 62-212.400(2)(g), 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 pounds per hour. *{Permitting Note: This is equivalent to 81 ppmvd @ 7% oxygen.}* [Rule 62-212.400(5)(c), 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(5)(c), F.A.C.]

   e. Particulate Matter ($PM/PM_{10}$): As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.026 lb/MMBtu and 24.3 pounds per hour. [Rule 62-212.400(5)(c), F.A.C.]

   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 pounds per hour. *{Permitting Note: This emission standard is also a surrogate for sulfuric acid mist (SAM) emissions.}* [Rule 62-212.400(5)(c), 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 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(5)(c), F.A.C.]

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

   a. Carbon Monoxide (CO): As determined by CEMS data, CO emissions shall not exceed 1285 tons per consecutive 12 months. *{Permitting Note: Compliance with the annual CEMS standard ensures that the project is not subject to PSD preconstruction review for CO emissions.}* [Rules 62-4.070(3) and 62-212.400(2)(g), F.A.C.]

   b. Nitrogen Oxides (NOx): As determined by CEMS data, NOx emissions shall not exceed 81 ppmvd @ 7% oxygen based on a 30-day rolling average. [Rule 62-212.400(5)(c), F.A.C.]

### 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. A full written report on the malfunctions shall be submitted in a quarterly report. [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 data collected (including startup, shutdown, and malfunction) shall be used to determine compliance with the 12-month rolling emissions standard based on CEMS data. Emissions in excess of the 12-month rolling emissions standard are not allowed.

    b. *NOx Emissions*: NOx CEMS data collected during startup, shutdown, and malfunction 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 and the permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

        4) For the period of excluded data, NOx emissions shall not exceed 162 ppmvd @ 7% oxygen based on a block average of the excluded CEMS data for the period identified as a startup, shutdown, or malfunction (alternative standard).

    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. *{Permitting Note: This alternate opacity standard does not impose a separate annual testing 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 bagasse fuel firing rate (tons per hour) shall be carefully monitored and

recorded. 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: the bagasse feed rate with fuel analysis and steam parameters with enthalpies. Results of the test shall be submitted to the Department within 45 days of completion. The tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. [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, CO, 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 each of these pollutants shall also be conducted during each federal fiscal year (October 1$^{st}$ to September 30$^{th}$). Tests shall be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate when firing only bagasse. CO CEMS data shall be reported for each run of the required test for VOC emissions. NOx CEMS data shall be reported for each run of the required tests for ammonia slip. Also, CEMS data for CO and NOx emissions may be used to demonstrate compliance with the initial stack test standards for these pollutants. 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. *{Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}* [Rules 62-212.400(5)(c) 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<br>*{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<br>*{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)<br>*{Note: The method shall be based on a continuous sampling train.}* |
| 18 | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography)<br>*{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(5)(c), 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(5)(c), 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 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*: A representative sample of bagasse 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 to determine emissions from the boiler stack and shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. The required RATA tests shall be performed using EPA Method 10 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 automatic dual span capabilities with maximum span values of 1000 ppmvd and 10,000 ppmvd.

    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 (CO and 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 "ppmvd @ 7% oxygen".

e. *24-Hour Averages (CO)*: Each 24-hour block shall begin at midnight of each operating day and shall be determined by averaging 24 consecutive 1-hour averages for each operating day. If the boiler operates less than 24 hours during the block, the 24-hour average shall be determined by averaging the available valid 1-hour block averages for actual boiler operation. Final results shall be recorded in terms of "ppmvd @ 7% $O_2$" and "pounds per day". [Rule 62-212.400(BACT), F.A.C.]

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 "ppmvd @ 7% $O_2$".

g. *Annual Averages (CO)*: 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(5)(c), F.A.C.]

19. COMS: In accordance with the provisions of NSPS Subparts A and Db, the permittee shall install, operate, and maintain a continuous opacity monitoring system (COMS) to demonstrate continuous compliance with the opacity standard. *{Permitting Note: NSPS Subpart Db establishes an opacity standard for the firing of "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. See Appendix D of this permit for additional related NSPS requirements.}* [Rule 62-204.800, F.A.C.; 40 CFR 60.48b(a)]

20. Alternate Opacity Monitoring Plan: With prior written approval from EPA Region 4, the permittee may 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 to demonstrate compliance with the opacity standards of the permit.

    [Applicant Request; Rule 62-4.070(3), F.A.C.; §60.48b(a)]

    *{Permitting Note: At the time of the final permit issuance, EPA Region 4 had not yet approved the above alternate sampling procedure.}*

21. 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, 1-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 blocks beginning at the top of each hour.

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(5)(c), F.A.C.]

22. 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(5)(c), F.A.C.]

23. Wet Cyclone: 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) and a manometer (or equivalent) to monitor the pressure drop (inches of water). 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(5)(c), F.A.C.]

**RECORDS AND REPORTS**

24. 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), bagasse firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-4.070(3), F.A.C.]

25. 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(BACT), F.A.C.]

26. Quarterly CO and NOx Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and NOx emissions including periods of startups, shutdowns, malfunctions, and CEMS systems monitor availability for the previous quarter. 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.]

## B. Bagasse Handling System

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

| ID | Emission Unit Description |
|---|---|
| 027 | Bagasse Handling System |

### EQUIPMENT

1. Modification of Existing System: The permittee is authorized to 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 handling system. [Design; Rule 62-212.400(2)(e) and (g), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive particulate matter, bagasse conveyors shall be enclosed. Dust collectors shall be installed on the conveyor transfer points. The preliminary design for the bagasse 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 duct collectors described above will be installed.}* [Design]

### 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(5)(c), F.A.C.]

### TESTING REQUIREMENTS

4. Opacity Tests: Within 180 days of completing construction of the bagasse 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(5)(c) 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.]

# SECTION 4. APPENDICES

## Contents

## 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;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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

*{Permitting Note: 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(2), F.A.C.]

## NSPS Requirements

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(7)(b), F.A.C.

| EU No. | Description |
|---|---|
| 028 | Boiler 8 – Spreader stoker boiler firing bagasse rated at a maximum continuous steam production rate of 500,000 pounds per hour (24-hour average) |

**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(7)(b), 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 for the new unit.}*

§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.

*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.

(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 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 $NO_2$), or

(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.

(i) Compliance with the emission limits under this section is determined on a 30-day rolling average basis.

*{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 only distillate oil during a cold startup. However, such a startup will last only a few hours before bagasse is introduced. 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 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.

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

*{Permitting Note: NSPS Subpart Db imposes only an 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 ($\leq$ 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, the permittee has requested approval from EPA Region 4 for an alternate procedure that includes additional EPA Method 9 observations when firing oil and monitoring the total ESP secondary voltage as an indicator of proper functioning and effective performance of the ESP.}*

§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.

(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 COMS, the permittee has requested approval from EPA Region 4 for an alternate procedure that includes additional Method 9 observations when firing oil and monitoring the total ESP secondary voltage as an indicator of proper functioning and effective performance of the ESP.. 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.}*

**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 pounds per hour based on a maximum 1-hour heat input rate of 1030 MMBtu per hour. The maximum continuous steam production is 500,000 pounds per hour based on a maximum heat input rate of 936 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. 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.

*Bagasse Handling System*: To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

**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: Bagasse Handling System* | | |
| Opacity [c] | There shall be no visible emissions ($\leq$ 5% opacity) from the dust collector outlets. | |
| *EU-028: Boiler 8* | | |
| CO [d] | 0.38 lb/MMBtu<br>(Equivalent: 363 ppmvd @ 7% $O_2$) | 1285 tons per consecutive 12 months, (rolling total) |
| NOx | 0.14 lb/MMBtu<br>(Equivalent: 81 ppmvd @ 7% $O_2$) | 81 ppmvd @ 7% $O_2$, 30-day rolling average (normal operation)<br>162 ppmvd @ 7% $O_2$, average during startup or shutdown |
| PM | 0.026 lb/MMBtu | Not Applicable |
| $SO_2$ (Surrogate for SAM) | 0.06 lb/MMBtu<br>(Equivalent: 25 ppmvd @ 7% $O_2$) | 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<br>(Equivalent: 111 ppmvd @ 7% $O_2$) | Not Applicable |
| Opacity [c] | During normal operation, stack opacity shall not exceed 20% based on a 6-minute block average.<br>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, 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: CO (Method 10); NOx (Method 7E); PM (Method 5); $SO_2$ (Method 6C); VOC (Methods 18 and 25A, as propane). 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, 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, or malfunction. The alternate NOx standard then applies, which is an average of the CEMS data for the period of startup or shutdown. The CO monitor shall meet the requirements of Performance Specification 4 or 4A in Appendix B of 40 CFR 60. 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. In lieu of the COMS requirements for Boiler 8, the permittee has requested approval from EPA Region 4 for an alternate sampling procedure that includes additional EPA Method 9 observations when firing oil and monitoring the total ESP secondary voltage as an indicator of proper functioning as well as effective performance of the ESP. If approved by EPA Region 4, the permittee may use the alternate sampling procedure.

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 operating new Boiler 8.

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 this project.

*Determination By:*

(DRAFT)

Jeff Koerner, P.E., Project Engineer (Date)
New Source Review Section

*Recommended By:*

(DRAFT)

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

*Approved By:*

(DRAFT)

Michael G. Cooke, Director (Date)
Division of Air Resources Management

## 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 hours to reach the desired superheater steam temperature of 500° F. Once this temperature is reached, bagasse 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.
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 is 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 during normal operation, the boiler exhaust carbon monoxide content is expected to be in the range of 400 ppmvd @ 7% oxygen based on a 24-hour average, excluding emissions during startup and shutdown. The required carbon monoxide CEMS shall report daily CO emission averages in these units. 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 carbonaceous fuels such as bagasse, 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 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 bagasse 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) |

| **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 ............. _____
   b. Shutdowns ................ _____        d. Total ........................ _____
3. On a separate page, summarize each malfunction event, the cause (if known), and corrective actions taken.
4. 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** |
|---|---|
| | |

**SENDER: *COMPLETE THIS SECTION***

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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation
Post Office Drawer 1207
Clewiston, FL 33440-1207

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by (*Please Print Clearly*) L Harris

B. Date of Delivery 9-29-03

C. Signature

X L Harris

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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William A. Raiola
*Street, Apt. No.; or PO Box No.*
PO Drawer 1207
*City, State, ZIP+4*
Clewiston, FL 33440-1207

PS Form 3800, January 2001 See Reverse for Instructions

# Memorandum

# Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief
Bureau of Air Regulation

THROUGH: Al Linero, Manager — AAL 9/18
New Source Review Section

FROM: Jeff Koerner, New Source Review Section — JK

DATE: September 18, 2003

SUBJECT: Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft PSD Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is October 3, 2003. I recommend your approval of the attached Draft Permit for this project.

Attachments

BEST AVAILABLE COPY

## P.E. CERTIFICATION STATEMENT

**PERMITTEE**

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

Draft Air Permit No. PSD-FL-333
Project No. 0510003-021-AC
Clewiston Sugar Mill and Refinery
Proposed Boiler 8 Project

**PROJECT DESCRIPTION**

The United States Sugar Corporation (U.S. Sugar) operates the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The facility currently has five existing boilers that primarily fire bagasse to provide steam for the mill and refinery. U.S. Sugar proposes to construct a new spreader stoker boiler (Boiler 8) with a maximum continuous steam production rate of 500,000 pounds per hour to support the sugar mill and refinery operations of the existing plant. It will purportedly be the largest bagasse-fired boiler in the United States. It will also fire distillate oil as a restricted alternate fuel for startup and supplemental uses. As part of the project, existing Boiler 3 will be permanently shut down and the bagasse handling system will be modified to accommodate Boiler 8. Actual emissions of several small existing miscellaneous activities in the mill and refinery may also occur.

The project is subject to PSD preconstruction review for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. The draft permit includes emissions standards that represent the Department's preliminary determination of the Best Available control Technology (BACT) for each PSD-significant pollutant. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design along with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used to minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, bagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

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

9-18-03
(Date)

**Golder Associates Inc.**
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

July 21, 2003

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RECEIVED
JUL 22 2003
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Attention: Mr. Jeffery Koerner, P. E.

RE: UNITED STATES SUGAR CORPORATION (U.S. SUGAR) – CLEWISTON MILL
PROPOSED NEW BOILER NO. 8
DEP PROJECT NO. 0510003-021-AC (PSD-FL-333)
ADDITIONAL INFORMATION RESPONSE #3

Dear Mr. Koerner:

Thank you for meeting with me and representatives of U. S. Sugar on May 28$^{th}$ regarding the Boiler No. 8 PSD permit application. During the meeting, and in a follow-up letter dated June 16, 2003, the Department requested certain additional information in order to complete the review of the application. The additional information requested is provided below.

1. **SNCR System**

The current design for Boiler No. 8 is for the uncontrolled $NO_x$ emissions to be in the range of 0.24 to 0.28 lb/MMBtu. This is in part a result of the necessity to design the boiler for low CO emissions. U. S. Sugar has proposed a CO emissions limit of 363 ppmvd @ 7% O2 (467 ppmvd @ 3% O2), equivalent to 0.38 lb/MMBtu. This limit is much lower than the current limit of 0.7 lb/MMBtu for Boiler No. 7 at Clewiston. The upcoming MACT standards for new industrial boilers could result in even a lower CO limit (the proposed MACT limit is 400 ppmvd @ 3% O2, equivalent to about 0.32 lb/MMBtu, which is lower than U. S. Sugar's proposed limit). We believe the uncontrolled $NO_x$ emissions range for Boiler No. 8 is higher than the design of the New Hope Power Partnership boilers, which were constructed about 8 years ago, because of the necessity to design the boiler for low CO emissions. In fact, Boiler No. 8 will be designed much differently than the New Hope Power boilers.

The Department claims that there is substantial information available from wood/bagasse fired boilers proving that SNCR is capable of consistently reducing $NO_x$ by 40% to 50%. The only plant that we know of is Okeelanta/New Hope Power, which almost continuously burns a 50/50 mixture of wood and bagasse to maintain combustion stability and even out the fluctuations in the bagasse quality. The Department also makes no mention of the ammonia slip levels.

The Department states that it does not distinguish between wood and bagasse as a fuel. It is possible to do this if one analyzes the fuel on a dry, ash free basis, but not when evaluating the fuel on an 'as-fired' basis. Bagasse, unlike wood, is largely dependent upon an upstream process to determine the 'as-fired' fuel quality. The final moisture of the bagasse, during the crop season, is dependent upon the mill operation (i.e., throughput, amount of imbibition water added, the condition of the mill rolls, the roll settings, etc.). During the off-crop season, when bagasse is fed from the outside storage area, the moisture constant is dependent on the moisture content when placed into storage, the time in storage, and the weather conditions during that time. During dryer periods, the moisture content can be much lower than during dryer periods, contributing to higher uncontrolled $NO_x$ emissions from the boiler.

The ash content in the bagasse is also variable and affects the 'effective moisture' of the bagasse. A higher ash content for a given fuel moisture makes the fuel more difficult to burn and therefore affects the required excess air ratios and overfire air distribution. As described previously to the Department, the Clewiston mill sugarcane is grown primarily on "sand" lands, and the resulting bagasse contains sand (which also ends up in the ash), which also contributes to this variability.

In summary, it is the significant variability in the bagasse fuel quality that makes it difficult to maintain consistently low uncontrolled $NO_x$ emissions.

The 'process dependency' of bagasse quality in itself suggests that bagasse is distinct from wood. The moisture and ash content of wood is also variable but it tends to be consistent for a particular source. This makes the boiler combustion control much more manageable and ultimately leads to more consistent uncontrolled emissions.

The primary reason for NOT selecting a water-cooled grate was one of emissions control. The ash removal mechanism of a water-cooled vibratory grate is to shake the grate through an eccentric or cam mechanism. This periodic 'shaking' causes higher particulate and CO emissions and therefore also influences uncontrolled $NO_x$ emissions. In addition to the 'shaking' problem, the suppliers of the water cooled grates require a higher undergrate air temperature than has been selected for the Boiler No. 8 design. The higher undergrate air temperature aggravates uncontrolled $NO_x$ as it increases the primary flame temperature.

The Boiler No. 8 furnace (as designed) has been modelled using Computational Fluid Dynamics (CFD). Thermal Energy Systems (TES), the firm designing Boiler No. 8, states that the results of the CFD modelling confirm the correct selection of the furnace geometry and the overfire air configuration for stable combustion and optimum CO emissions. However, $NO_x$ modelling of solid fuel-fired boilers is extremely complex, and while some claim to have resolved this, TES has doubts as to whether CFD predictions of uncontrolled $NO_x$ emissions can be used as a basis for specifying uncontrolled $NO_x$ limits. Their understanding of the state of art is that, at best, some people claim that $NO_x$ modelling can be used to obtain relative numbers from a given geometry but not absolute numbers.

Excess air is a function of the 'effective' fuel moisture. Low excess air cannot be used when burning a high moisture biomass fuel in suspension because the fuel tends to pile on the grate. This comes back to the variable quality of bagasse and the difficulty in maintaining ideal combustion conditions consistently with a variable process. For example, if one designs the boiler for a low moisture fuel, trouble will be encountered as soon as the moisture increases by a couple of percentage points. On the other hand, if the boiler is designed for burning a high moisture fuel, the uncontrolled $NO_x$ emissions will increase as soon as the fuel moisture drops appreciably below the design level.

Flue gas recirculation is normally used to quench the flame, reducing both temperature and oxygen levels, thereby reducing the uncontrolled $NO_x$ emissions. The problem with using flue gas recirculation on a bagasse boiler is the ability to maintain a high enough flame temperature to maintain combustion. For this reason, we do not believe flue gas recirculation is an option for a bagasse-fired boiler.

In summary, the above discussion underscores the uncertainty of predicting uncontrolled $NO_x$ emissions from a highly variable fuel. The best estimate is still in the range of 0.24 to 0.28 lb/MMBtu. However, in order to account for this variability, increasing the averaging time associated with any $NO_x$ limit is necessary, to avoid short-term excursions.

Based on the current boiler design, additional information regarding the performance of the SNCR system proposed for Boiler No. 8 is presented in the attached letter from Fuel Tech (Attachment A). FTI states that at an uncontrolled emission rate of 0.28 lb/MMBtu, a controlled $NO_x$ emission rate of 0.19 lb/MMBtu is achievable on a continuous basis (equivalent to 32% $NO_x$ reduction). However, we have also received a quote from another SNCR vendor, De-$NO_x$ Technologies (DNT). DNT has quoted a $NO_x$ removal efficiency of 50% at an uncontrolled $NO_x$ level of 0.24 lb/MMBtu (also attached).

Based on this information, and assuming an average uncontrolled $NO_x$ emission rate as high as 0.28 lb/MMBtu, U. S. Sugar believes it can meet an $NO_x$ limit of 0.14 lb/MMBtu based on a 12-month rolling average, excluding startup, shutdown and malfunction. The 12-month rolling average limit is requested in order to account for the variability in boiler operating conditions and fuel conditions, as described above and in the FTI letter. It is the variability of the process and the fuel quality under normal operating conditions that makes the controlled figure of 0.14 lb/MMBtu impossible to meet on a continuous basis. Achieving greater than 50 percent $NO_x$ reduction on a continuous basis may not be achievable based on the bagasse fuel characteristics, limited reactant residence time, changing boiler loads, etc. However, we believe this may be achievable on an average basis.

The proposed limit is lower than New Hope Power's $NO_x$ limit of 0.15 lb/MMBtu. We therefore believe this represents a significant advancement in $NO_x$ reduction, given the higher uncontrolled emissions, fuel variability, and other factors for Boiler No. 8.

The proposed lower $NO_x$ limit as a 12-month rolling average requires that portions of the PSD application be revised. These revisions are presented in Attachment B.

2. **Excess Emissions From Boiler No. 8**

**Further Description of Startup and Shutdown Conditions**
The anticipated startup/shutdown procedures for Boiler No. 8 were presented in Attachment UC-EU1-J6 of the permit application form. Further information is presented below regarding the startup and shutdown procedures in order to better address potential excess emissions during startup.

In a normal start-up, Boiler No. 8 will be started on fuel oil. One burner will be used (and from time to time will shut it down if the temperature rise is too fast) to bring the boiler up in approximately 4 to 5 hours at a superheater steam temperature rise of about 100 to 120 deg. F per hour. Once a steam temperature of about 500 deg. F is reached, bagasse is fed onto the grate until a fire is established across the entire grate. Full steaming rate is usually reached in about 30 to 60 minutes after bagasse begins to be fed to the boiler. Normally the ESP is started before any of the fuel oil burners are lit, and always before any bagasse is fed onto the grate. The ESP requires about 30 to 60 minutes of purging using ambient air prior to activation.

To initiate shutdown, the bagasse fuel feed is terminated. The air pollution control equipment is not shutdown until the fuel flow is stopped.

It is estimated, based on past experience and the year-around use of Boiler No. 8, that the boiler will have 4 to 6 cold starts and 6 to 8 warm starts per year. This could vary depending on weather conditions, plant operating conditions, boiler maintenance requirements, etc.

Anticipated emissions during startup and shutdown conditions are described below.

**PM Emissions and Opacity**
The wet sand separator is activated prior to startup beginning, and the ESP is activated prior to introducing any bagasse to the boiler. Only fuel oil is burned until the ESP is activated. As a result, excess PM emissions are minimized during startup. Combustion conditions when initially firing fuel oil may not be optimum, therefore higher emissions than 0.026 lb/MMBtu may result. However, the fuel input and boiler

load are low during such conditions. Therefore, the maximum mass emissions stated in the application (26.8 lb/hr) should not be exceeded during startup.

Since combustion conditions during startup may not be optimum, there is a possibility for excess opacity. Setting in operation of the ESP prior to firing any bagasse, along with firing fuel oil only initially, will minimize any excess opacity from the stack serving Boiler No. 8. Opacity during startup is expected to be below 20 percent most of the time, but wet fuel may cause some short-term excursions.

During shutdown, the bagasse fuel input is terminated and the remaining bagasse on the grate is combusted. The wet sand separator and ESP continue to operate, and adequate combustion air is provided to complete combustion. Therefore, no excess PM or opacity emissions are expected during shutdown.

**$NO_x$ Emissions**

$NO_x$ emissions in excess of the proposed limit of 0.14 lb/MMBtu are not expected to occur provided the limit is on a 12-month rolling average. However, this level could be exceeded on a short-term basis during boiler startup. The SNCR system cannot be activated until the appropriate temperature window within the boiler is achieved. This temperature window is expected to be achieved within about 4 to 5 hours of initial fuel firing, when the boiler is burning fuel oil. During this time, the fuel input and boiler load are gradually increased. In addition, furnace temperatures are lower during such periods, thereby limiting $NO_x$ emissions. Therefore, the maximum short-term $NO_x$ mass emissions stated in the application (0.28 lb/MMBtu and 288.4 lb/hr, as revised through this submittal) should not be exceeded during startup.

During shutdown, the bagasse fuel input is terminated and the remaining bagasse on the grate is combusted. The SNCR system continues to operate as long as the appropriate temperature window is maintained in the boiler. Therefore, no excess $NO_x$ emissions are expected during shutdown.

During all hours of boiler operation, the SNCR system will be operated automatically based on furnace temperatures and the $NO_x$ continuous emissions monitoring system (CEMS). Once temperatures in the furnace are correct for reactant injection, the system will automatically feed the appropriate amount of reactant to maintain emissions at 0.14 lb/MMBtu on an average basis.

It is noted that since a CEMS for $NO_x$ will be required, U. S. Sugar will be able to quantify emissions during startup and shutdown after the boiler begins operating, based on actual operation of the boiler.

**CO and VOC Emissions**

CO and VOC emissions from Boiler No. 8 are expected to behave in a similar manner, as both are dependent upon good combustion. Therefore, the following discussion will apply to both of these pollutants.

Normally, only fuel oil is burned during initial startup of the boiler. This is to heat up the boiler and the ESP, and to develop the appropriate temperature window in the boiler. Burning fuel oil only during this period minimizes emissions of CO/VOC. CO levels when burning fuel oil are expected to be low. CO/VOC tends to increase when starting to burn bagasse, especially if the bagasse is wet. To minimize emissions, the startup period is minimized by bringing the boiler on-line and up to steam rate as quickly as possible, and following good combustion practices, as described in the application.

The maximum CO emissions stated in the application (6.5 lb/MMBtu for 1-hour and 4.5 lb/MMBtu for 8-hr average, equivalent to about 6,200 ppm and 4,300 ppm @ 7% $O_2$, respectively) are the highest expected during startup or shutdown. These emissions are based on CEM data for New Hope Power Partnership boilers. These maximum emissions were included in the air quality modeling analysis, and it was demonstrated that such emissions would not result in adverse air quality impacts. It is not expected that this level of emissions will be exceeded during startup or shutdown of the new boiler. Also, the fuel input and boiler load are lower during such conditions. Therefore, the maximum mass emissions of 6,695 lb/hr for CO and 61.8 lb/hr for VOC, as stated in the application, should not be exceeded during startup.

During shutdown, the bagasse fuel input is terminated and the remaining bagasse on the grate is combusted. Adequate combustion air is provided to complete combustion. Therefore, no excess CO/VOC emissions are expected during shutdown.

It is noted that since a process monitor for CO will be required, U. S. Sugar will be able to quantify emissions during startup and shutdown after the boiler begins operating, based on actual operation of the boiler.

**Exclusion of Excess Emissions During Startup/Shutdown Conditions**
Since startup and shutdown conditions do not represent the normal operation of the boiler, and excess emissions may occur during such periods, it is requested that emissions during these periods be excluded from the lb/MMBtu emission limits. A CEMS will be required for CO and $NO_x$. Including startup/shutdown emissions for compliance purposes would make it difficult to meet such limits. It is noted that startup/shutdown emissions have be excluded from compliance with emission limits for other similar wood/bagasse-fired boilers, such as for New Hope Power Partnership. The Florida air rules specifically allow excess emissions due to startup, shutdown or malfunction, for up to two hours in any 24-hour period, provided the magnitude and duration of such periods is minimized to the extent practicable (Rule 62-210.700, F. A. C.).

For Boiler No. 8, U. S. Sugar proposes to define the startup period as the period until steam generation reaches 300,000 lb/hr (about 60% of maximum steam load). This is based on the expected turndown ratio for the boiler.

The following permit conditions are recommended for Boiler No. 8. These conditions are structured after New Hope Power's latest PSD permit.

Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction of Boiler No. 8.

a. *Definitions*

1) Excess emissions are 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 that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

2) Startup is the commencement of operation of the boiler after a shut down or cessation of operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for Boiler No. 8 shall end once steam generation reaches 300,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

3) Shutdown is the cessation of the operation of Boiler No. 8 for any purpose after steam generation drops below 300,000 pounds per hour.

4) Malfunction is 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.]

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of excess emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the boiler.

   1) Distillate oil or clean wood shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the ESP has been adequately purged, as recommended by the ESP manufacturer, it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. XX. The ESP shall be on line and functioning properly before firing any bagasse. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown.

   2) Hourly $NO_x$ emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 12-month compliance averages. No more than six (6) hourly emission rate values shall be excluded in a 24-hour period due to a cold startup. No more than three (3) hourly emission rate values shall be excluded in a 24-hour period due to a warm startup. No more than two (2) hourly emission rate values shall be excluded in a 24-hour period due to a malfunction. No more than two (2) hourly emission rate values shall be excluded in a 24-hour period due to a shutdown. No more than 183 hourly emission rate values shall be excluded during any calendar quarter.

   3) To "document" a malfunction during which excess emissions occurred, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions associated with excess emissions, that occurred during the year for the boiler. The report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

3. **Alternative Opacity Monitoring Plan**

In the application, U. S. Sugar presented an Alternative Opacity Monitoring Plan to be implemented in lieu of a continuous opacity monitoring system (COMS). The Department has indicated that despite the fact that a COMS may not be required by the NSPS, there may be other reasons to require the COMS, i.e., as a surrogate for PM emissions. However, U. S. Sugar believes that there are additional reasons for not requiring a COMS on Boiler No. 8. These reasons are as follows:

- The stack gas constituents are not conducive to accurate opacity readings. The stack gases will contain significant moisture, i.e., 20 percent or more by volume. Unreacted urea may be present. Ammonia and ammonia compounds will be present, including ammonium bisulfate, which is known to have a high reflectance. All of these compounds can result in inaccurate opacity readings by the COMS.

- There is no demonstrated correlation between opacity and PM emissions for a solid-fueled boiler. No such correlations are known to have even been attempted for a bagasse-fired boiler.

- Boiler No. 8 will be subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR Part 64. As such, U. S. Sugar will be required to investigate and propose surrogate parameters for monitoring PM on a continuous basis. CAM would apply to the new boiler upon inclusion in the Title V operating permit.

- Boiler No. 8 will have a CEMS for CO, as part of good combustion practices (GCPs) for the boiler. Corrective action will be required if the CO exceeds a specified level. Since GCPs, CO, PM and opacity are all related, having the CO monitor renders an opacity monitor as less important in ensuring that good combustion is taking place.

After the new Boiler No. 8 is started up, U. S. Sugar will investigate surrogate parameters for PM emissions, and propose the surrogate parameters along with parameter ranges as part of the Title V revision application. The tentative monitoring approach would be to use ESP power as the indicator of PM emissions. The CAM rules, as described at 40 CFR 64.4(d) and (e), provide for an adequate amount of time to install and test necessary monitoring equipment, including the submission of a test plan and schedule to obtain performance data. U. S. Sugar will conduct a testing program to determine if ESP power is a reliable indicator of actual PM emissions. Initial testing will be completed within 90 days of initial compliance testing of the boiler. The results of the testing as well as the selected indicator parameter ranges will be submitted to the Department with the Title V permit application. The preliminary monitoring approach is summarized in the following table.

| | **Indicator No. 1** |
|---|---|
| Indicator | ESP secondary voltage and current are measured for each field to determine the total power to the ESP. |
| Measurement Approach | The secondary voltage is measured using a voltmeter and the secondary current is measured using an ammeter. The total power (P expressed as kW) input to the ESP is the sum of the products of the secondary voltage (V) and current (I) in each field. ($P = V_1I_1 + V_2I_2 + \ldots + V_nI_n$) |
| Indicator Range | An excursion is defined as an ESP power input less than a minimum kW (to be determined). Excursions trigger an inspection, corrective action, and a reporting requirement. |
| Data Representative-ness | The voltage and current are measured using standard instrumentation provided for this purpose. |
| Verification of Operational Status | NA |
| QA/QC Practices and Criteria | Confirm the meters read zero when the unit is not operating. |
| Monitoring Frequency | The secondary voltage and current are measured continuously and used to calculate the power input every 15 minutes. |
| Data Collection Procedures | The hourly average power input is calculated and recorded. |
| Averaging Period | 1-hour block averaging period. |

ESP parameters are generally recognized indicators of PM emissions. In an ESP, electric fields are established by applying a direct-current voltage across a pair of electrodes, a discharge electrode and a collection electrode. Particulate matter suspended in the gas stream is electrically charged by passing through the electric field around each discharge electrode (the negatively charged electrode). The negatively charged particles then migrate toward the positively charged collection electrodes. The particulate matter is separated from the gas stream by retention on the collection electrode. Particulate is removed from the collection plates by shaking or rapping the plates.

Generally, ESP performance improves as total power input increases. This relationship holds true when PM and gas stream properties (such as PM concentration, size distribution, resistivity, and gas flow rate) remain stable and all equipment components (such as rappers, plates, wires, hoppers, and transformer-rectifiers) operate satisfactorily.

The secondary voltage drops when a malfunction, such as grounded electrodes, occurs in the ESP. When the secondary voltage drops, less particulate is charged and collected. Also, the secondary voltage can remain high but fail to perform its function if the collection plates are not cleaned, or rapped, appropriately. If the collection plates are not cleaned, the current drops. Thus, since the power is the product of the voltage and the current, monitoring the power input will provide a reasonable assurance that the ESP is functioning properly. Problems that may not be detected by monitoring other parameters individually will be manifested in the total power input.

The indicator ranges will be determined through a testing program. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported.

It is noted that EPA and EPRI are conducting ongoing studies regarding PM emissions and ESP operating parameters. By the time that the new Boiler No. 8 is started up, additional knowledge should exist regarding the relationship between PM emissions and ESP parameters. As a result, the tentative plan presented above is subject to change.

Based on the above plan, we request that a COMS not be required for Boiler No. 8, and the Alternative Monitoring Plan be adopted.

4. **<u>Air Quality Modeling Analysis</u>**

Based on the Department's comments, the building dimensions used in the modeling have been revised to match the aerial photograph submitted with the application. The modeling has been re-executed for $PM_{10}$ based on DEP's request, and the revised results are presented in Attachment C. These results change, if at all, from those presented in the original application.

5. **<u>Gaseous Pollutant Concentrations</u>**

Equivalent concentrations of gaseous pollutants are presented in the following table.

| Pollutant | Emission Rate (lb/MMBtu) | Emission Rate (lb/hr) | Concentration @ 3% O2 | Concentration @ 7% O2 |
|---|---|---|---|---|
| Sulfur Dioxide | 0.06 | 56.16 | 32 ppmvd | 25 ppmvd |
| Nitrogen Oxides | 0.14 | 131.0 | 104 ppmvd | 82 ppmvd |
| Carbon Monoxide | 0.38 | 356.0 | 467 ppmvd | 363 ppmvd |
| Volatile Organic Compounds* | 0.06 | 56.16 | 96 ppmvd | 75 ppmvd |

* Reported as carbon.

6. **Continuous CO Monitoring**

The Department has indicated that a continuous process monitor will be required on Boiler No. 8, and will be used to trigger corrective action when CO reaches a certain level in the boiler. This is the same type of monitoring currently required for Boiler No. 4 at Clewiston.

The MACT standards for industrial boilers, as currently proposed, require a continuous CO monitor that meets the requirements of 40 CFR 60, Appendix B, Performance Specification PS-4A. In addition, the quality assurance requirements of 40 CFR Appendix F would apply. It is our understanding that the CO limit under the industrial boiler MACT will be promulgated as a work practice standard, and will require corrective action when exceeded, but not be considered a violation unless corrective action is not initiated.

In light of these tentative requirements, U. S. Sugar will agree to installing a CO monitor capable of meeting the requirements of the MACT rule, but request that the monitor only be used as a process monitor with an associated action level.

7. **Baseline CO Emissions From Boiler No. 3**

Prior to 2002, the annual CO emissions reported for Boiler No. 3 in the Annual Operating Report (AOR) to DEP were based on a factor for wood waste combustion (13.6 lb/ton from Table 1.6-2 of AP-42). This factor had been used for many years previously by U. S. Sugar, and for consistency sake, they had continued to use this factor. However, beginning with the 2002 AOR, a CO emission factor based on test data from Boiler No. 3 was used (35.3 lb/ton or 4.9 lb/MMBtu), as this factor is more representative of actual emissions from the boiler. The test data upon which the factor is based are shown in the attached Table A. In preparing the application, we recalculated the 2001 CO emissions using the more appropriate factor. We believe these emissions are most representative of the actual emissions from Boiler No. 3.

8. **ESP Design Specifications**

The ESP vendors have provided preliminary scoping and budgeting information for the ESP. They have based their efficiency numbers on an assumed particulate matter (PM) inlet grain loading of 1.0 lb/MMBtu. Then, using our design specification of 0.026 lb/MMBtu at the outlet, they have provided the equivalent removal efficiency. However, the inlet grain loading could be substantially higher than 1.0 lb/MMBtu. There is little data available on the uncontrolled PM emissions from a bagasse-fired boiler. AP-42 presents a factor, which is shown in the application, of 15.6 lb/ton of wet bagasse fired, which is equivalent to about 2.4 lb/MMBtu, depending on heating value of the bagasse. However, another EPA publication presents a factor of 5.05 lb/MMBtu (Non-fossil Fuel Fired Industrial Boilers- Background Information, EPA-450/3-82-007, March 1982). Based on this higher uncontrolled factor, the ESP efficiency required would be 99.5%. These are details that will need to be worked out with the ESP vendor prior to actual vendor selection or signing a purchase agreement. The final agreement will contain performance guarantees, as opposed to the "expected performance".

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In addition, Thermal Energy Systems has calculated the inlet dust loadings for a number of different conditions. For the design fuel (52 % moisture, 4 % ash) at 100 % MCR and for the worst-case EPS design (50 % moisture, 11 % ash) they are as follows:

| Measuring point | Units | Burden | |
|---|---|---|---|
| | | DESIGN FUEL | ESP DESIGN |
| Entry to ESP | lb/MMBTU | 1.45 | 5.19 |
| Exit from ESP | lb/MMBTU | 0.026 | 0.026 |
| Required ESP efficiency | % | 98.2 | 99.5 |

These figures include an allowance for the moisture added by the urea. The ESP design includes a 30% allowance for upset conditions. As shown, the ESP design will be capable of achieving a 99.5% removal efficiency.

The opacity specification provided by the ESP vendors at this time is also an "expected performance", and not a firm guarantee. Regardless, even if a 10% opacity was guaranteed by a vendor, this should not translate directly into a permit limit. Guarantees are typically based on very specific assumed operating conditions. The guarantee applies only if specific operating conditions are met. Guarantees are usually satisfied in the contract by a single performance test, again at specified operating conditions. These tests are typically performed under the best operating conditions, when the equipment is new and in the best working order. Under actual day-to-day operations, conditions may be different. As a result, any permit limits must reflective of this.

Thank you for consideration of this additional information. Please call or e-mail me if you have any questions concerning this information.

Sincerely,
GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P. E. # 19011
SEAL

DB

DB/jej

Enclosure

cc: Don Griffin
Ron Blackburn, DEP
C. Holladay
G. Worley, EPA
J. Bunyak, NPS

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Table A. CO Emission Tests Performed on Boiler No. 3- U.S. Sugar Corporation - Clewiston

| Unit | Boiler Type | Test Date | Stack Gas Flow Rate (dscfm) | Steam Rate (lb/hr) | Heat Input Rate (MMBtu/hr) | Bagasse Burning Rate [1] (TPH) | CO Emissions (EPA Method 10) lb/hr | CO Emissions (EPA Method 10) lb/MMBtu |
|---|---|---|---|---|---|---|---|---|
| Boiler 3 | Fuel Cell | 02/18/94 | 77,498 | 104,143 | 213.53 | 29.66 | 393.21 | 2.115 |
| Boiler 3 | Fuel Cell | 02/18/94 | 74,595 | 114,429 | 234.27 | 32.54 | 321.63 | 1.590 |
| Boiler 3 | Fuel Cell | 02/18/94 | 76,321 | 104,677 | 214.47 | 29.79 | 486.85 | 2.270 |
| Boiler 3 | Fuel Cell | 01/10/95 | 80,337 | 109,662 | 222.08 | 30.84 | 302.26 | 1.361 |
| Boiler 3 | Fuel Cell | 01/10/95 | 68,931 | 115,225 | 233.89 | 32.48 | 392.47 | 1.678 |
| Boiler 3 | Fuel Cell | 01/10/95 | 72,747 | 112,974 | 228.50 | 31.74 | 482.70 | 2.112 |
| Boiler 3 | Fuel Cell | 02/27/96 | 70,962 | 95,607 | 189.08 | 26.26 | 610.68 | 3.230 |
| Boiler 3 | Fuel Cell | 02/27/96 | 73,300 | 89,679 | 176.36 | 24.49 | 261.72 | 1.484 |
| Boiler 3 | Fuel Cell | 02/27/96 | 67,289 | 96,632 | 153.35 | 21.30 | 28.16 | 0.148 |
| Boiler 3 | Fuel Cell | 02/28/96 | 70,659 | 102,130 | 178.97 | 24.86 | 94.62 | 4.714 |
| Boiler 3 | Fuel Cell | 02/28/96 | 65,905 | 102,986 | 170.59 | 23.69 | 2063.82 | 10.225 |
| Boiler 3 | Fuel Cell | 02/28/96 | 70,791 | 108,000 | 179.10 | 24.88 | 1443.73 | 6.811 |
| Boiler 3 | Fuel Cell | 02/28/96 | 73,377 | 102,441 | 200.34 | 27.83 | 1742.13 | 8.696 |
| Boiler 3 | Fuel Cell | 02/28/96 | 70,591 | 105,179 | 205.69 | 28.57 | 1275.01 | 6.199 |
| Boiler 3 | Fuel Cell | 02/28/96 | 69,977 | 99,134 | 194.01 | 26.95 | 1619.93 | 8.350 |
| Boiler 3 | Fuel Cell | 02/29/98 | | 102,441 | 173.21 | 24.06 | 1742.13 | 10.058 |
| Boiler 3 | Fuel Cell | 02/29/98 | | 105,179 | 174.93 | 24.30 | 1275.00 | 7.289 |
| Boiler 3 | Fuel Cell | 02/29/98 | | 99,134 | 164.73 | 22.88 | 1619.33 | 9.830 |
| | Number of Runs | | 15 | 18 | 18 | 18 | 18 | 18 |
| | **MEAN** | | **72,219** | **103,870** | **194.8** | **27.06** | **897.5** | **4.898** |
| | MINIMUM | | 65,905 | 89,679 | 153.4 | 21.30 | 28.2 | 0.148 |
| | MAXIMUM | | 80,337 | 115,225 | 234.3 | 32.54 | 2,063.8 | 10.225 |

**Notes:**
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
TPH = tons per hour.

[1] Assumed 3,600 Btu/lb average heat content for wet bagasse, except where noted.

# ATTACHMENT A

# ADDITIONAL SNCR VENDOR INFORMATION

FUEL TECH
Technology for a renewed environment™

To Whom It May Concern:

Over the last six months, Fuel Tech, Inc. (FTI) has been working with U.S. Sugar Corporation and Thermal Energy Systems to develop a NOxOUT® SNCR system design capable of providing the best possible NOx reduction performance while maintaining some degree of operating flexibility for the new No. 8 boiler at the Clewiston Mill. The latest set of boiler design specifications, dated May 5, 2003, has been used by FTI to conduct a preliminary SNCR process evaluation covering a wide range of fuel conditions and baseline NOx concentrations.

In general, the result of our review indicates that NOxOUT® SNCR can provide a dependable and sustainable controlled NOx level of 0.15 lb/MMBtu for the "design" case and somewhat better performance for the other load cases, as long as certain operating conditions are made available to the SNCR process. Our review has covered a number of design parameters that are critical to the effectiveness of the SNCR process, including:

- Balance-of-plant impacts,
- Expected flue gas temperature at the point of injection,
- Access to the furnace and distribution of the urea reagent,
- CO concentration in the upper furnace,
- Residence time within the effective temperature window for the SNCR process,
- Baseline NOx concentration, and
- Ammonia slip.

While each of these parameters is critical to the SNCR process, FTI must take into consideration up-front potential balance-of-plant impacts that could affect plant operation. In particular, the expected size of the atomized urea droplets must be considered so as to avoid the potential impingement of liquid urea on the heat transfer surfaces. Under normal design conditions FTI would ensure that the urea droplets would completely evaporate, decompose into ammonia and isocyanic acid, and through reactions with the OH, O and H radicals, be converted to gas phase NH2 and NCO before entering the superheater region.

The selective, non-catalytic reactions occur in the gas phase between NH2 and NCO and various oxides of nitrogen. The process is optimized by releasing the reducing agent inside a temperature range within which significant NOx reduction can be obtained – this temperature range is known as the temperature window. Chemical release within the optimum temperature window ensures that the reducing agents will react with NOx and convert it to molecular nitrogen. If the chemical is released at temperatures higher than optimum, the reducing agent will oxidize into NOx. If the chemical is released at temperatures well below the optimum, the reactions will slow down significantly. Under the latter scenario, some ammonia from the original decomposition step of urea will not convert to NH2 but will survive intact, and be present downstream as "ammonia slip".

Given sufficient residence time to account for the reduced kinetic rates, reactions at lower temperatures typically lead to lower NOx levels. As mentioned above, however, these lower temperatures also lead to higher levels of ammonia slip, which generally is an undesirable byproduct. Fuel Tech tries to achieve maximum NOx reduction while maintaining low ammonia slip through the use of multiple injection levels and the careful selection of the spraying patterns developed through CFD and CKM modeling. Other owners of bagasse-fired boilers have experimented with larger than ideal urea droplets with extremely negative consequences. The larger droplets do not evaporate and decompose as quickly, and although the outlet NOx concentration may be lower, liquid urea may impinge on the tube surface and eventually eat through the boiler tube steel causing a leak and subsequent forced shutdown of the unit.

Other balance-of-plant considerations include the potential for ammonium bisulfate formation and visible emissions (ammonium chloride plume). These potential issues were taken into consideration for this application but since very little sulfur trioxide (except for light fuel oil firing) and/or hydrogen chloride would be present in the flue gas, these process-limiting impacts were dismissed.

As mentioned in the previous paragraphs, there are other design parameters and flue gas constituents that must be considered as part of the SNCR design process. For this application, we considered a high temperature in the injection zone of 2025°F for the low moisture bagasse case and a low temperature of 1600°F for the light fuel oil (LFO) and LFO/bagasse cases. Because of this wide range of temperatures and the need to maximize NOx reduction while limiting ammonia slip, FTI will be recommending three (3) levels of urea injectors to facilitate biasing of the injected reagent across the temperature window as necessary for optimum performance. Based on drawings of the proposed boiler we have reviewed, this furnace design offers an advantage over many of our existing installations – this furnace can be accessed at the lower two (2) injections levels from all four sides which will significantly aid in the distribution of the reagent.

Another other important consideration is the local concentration of CO within the specified temperature window. The design details indicate that the local CO will be limited to 400 ppm, but under various fuel and load conditions, we expect to see wide fluctuations in the CO concentration. It is important that outside of these fluctuations, the average concentration of CO stays near this design level.

When the NOxOUT® SNCR process was evaluated for this application, we used the projected concentration of 400 ppm in the post-combustion region of the furnace. The CO concentration is important in that when a higher than anticipated CO level is encountered, it changes the chemical environment and increases the formation of hydroxyl radicals, which are key components in the conversion of the ammonia and isocyanic acid to the reducing agents NH2 and NCO. If the temperature is relatively high, the NH2 will oxidize to NOx – an undesirable effect. In order to achieve effective NOx reduction, the chemical needs to be released at a lower temperature which is typically found closer to the furnace exit, with the net effect of reducing the residence time for the selective reactions.

In terms of expected NOx reduction performance and ammonia slip, our design analysis covered inlet NOx ranging from a maximum of 0.30 lb/MMBtu to a minimum of 0.20 lb/MMBtu. However, we placed the majority of our focus on the inlet NOx levels of 0.28 and 0.24 lb/MMBtu, which are more typical of the uncontrolled NOx levels we have seen in other bagasse-fired boilers.

Assuming that the uncontrolled NOx is 0.28 lb/MMBtu and the ammonia slip must be limited to 10 ppmv (average, as measured), our evaluation indicates that the best sustainable, controlled NOx for the design fuel and moisture is 0.18 lb/MMBtu. However, if the ammonia slip limit is relaxed to 25 ppmv, NOx can be controlled to just below 0.15 lb/MMBtu. The improved NOx reduction comes at the expense of a higher urea consumption rate and less effective chemical utilization, but we anticipate that the bulk of the ammonia will be removed in the scrubber and the actual concentration of ammonia leaving the stack will be much lower. Please note that the design details of the scrubber were not available at the time of our review and no guarantees are being offered for the actual NH3 removal efficiency in the scrubber.

At the "mean" inlet NOx level of 0.24 lb/MMBtu, chemical utilization is slightly better but the controlled NOx for the 10 ppmv slip design case is still 0.18 lb/MMBtu. At 25 ppmv slip, controlled NOx for the mean inlet NOx is projected to be at or below 0.14 lb/MMBtu.

Hopefully this letter summarizes the depth of the review we have conducted for this application and the number of process conditions that must be taken into account prior to establishing SNCR NOx control performance. Fuel Tech, Inc. stands by this analysis based on the design information provided and we would be pleased to discuss our analysis with any of the involved parties.

Design Performance Projections

**Expected NOx Baseline, 10 ppmv Ammonia Slip (average, as measured)**

| Type of Fuel | | Design H2O Bagasse | Design H2O Bagasse | Low H2O Bagasse | Avg. H2O Bagasse | High H2O Bagasse | High H2O Bagasse | Light Fuel Oil | LFO and Bagasse | LFO and Bagasse |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Case | | Series 1 | Series 2 | Series 3 | Series 4 | Series 5 | Series 6 | Series 7 | Series 8 | Series 9 |
| Gross Heat Input | MMBtu/hr | 886.2 | 424.3 | 804.5 | 843.9 | 844.5 | 920.0 | 359.2 | 894.8 | 402.8 |
| Baseline NOx | lb/hr | 212.7 | 101.8 | 192.7 | 202.4 | 202.7 | 220.9 | 71.8 | 214.5 | 96.6 |
| Baseline NOx | lb/MMBtu | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.20 | 0.28 | 0.28 |
| Target NOx | lb/MMBtu | 0.18 | 0.16 | 0.19 | 0.18 | 0.17 | 0.18 | 0.14 | 0.17 | 0.16 |
| Reduction | % | 27.5 | 32.5 | 25 | 27.5 | 30 | 27.5 | 30 | 30 | 32.5 |
| Average NH3 Slip | ppmv | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Expected Temperature at Injectors | F | 1850-1950 | 1650-1750 | 1925-2025 | 1875-1975 | 1800-1900 | 1825-1925 | 1600-1700 | 1725-1825 | 1600-1700 |
| Furnace CO Limit, Max Entering SH | ppm | 400 | 400 | 400 | 400 | 400 | 400 | 200 | 400 | 400 |
| NOxOUT-A | gph | 32 | 19 | 28 | 30 | 33 | 33 | 12 | 37 | 18 |

# DNT

*DE-NOX TECHNOLOGIES*

De-NOx Technologies, LLC
22 Partridge Lane
East Hampstead, NH 03826
(603) 974-1411
(815) 301-8450 E-fax
dwojichowski@de-nox.com
www.de-nox.com

July 2, 2003

Mr. Mike Cantrell, PE
McBurney Corp
1650 International Court
Norcross, GA 30093

Dear Mr. Cantrell,

SUBJECT:US SUGAR CLEWISTON SNCR PROPOSAL

Per your request, enclosed is a Budget Proposal to design, supply, and start-up the SNCR system for Boiler 8 at the Clewiston Mill.

Please call me if you have any questions.

Sincerely,

David Wojichowski, P.E.
President

# DNT

*DE-NOX TECHNOLOGIES*

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UNITED STATES SUGAR COMPANY
SNCR DESIGN SUPPLY PROPOSAL
EXECUTIVE SUMMARY

McBurney Corp has requested a budget quote for the design, supply, and start-up of one urea-based SNCR system for US Sugar's new 500,000 pph bagasse boiler in Clewiston, FL. Based upon the information provided, the bagasse boiler (much like wood or refuse) is an ideal candidates for SNCR since it has a generous furnace design and relatively low temperature entering the superheater. As such, the proposed system is guaranteed to provide 50 % NOX reduction, from 0.24 to 0.12 lb/MMBTU with an ammonia slip less than 15 ppmdv at 7%O2. The guarantee is predicated upon the existence of continuous emission monitoring for NOX with time averaging no more stringent than rolling 24 hour averages.

The challenge for the design is to accommodate the entire range of firing conditions – 100% load wet fuel, 100% load dry fuel, 50% load wet fuel, and auxiallary fuel firing. Further, the design must accommodate this operating envelope with a minimum of operator intervention while keeping the system simple and cost effective. To do so, the design allows for 3 injection zones, all automatically selected and operated from the local PLC controller. The lowest zone in furnace elevation is provided for low load on bagasse, the middle zone for high load on bagasse, and the highest zone for auxially fuel firing. Based upon the information provided in the Specification, the only question seems to be the location and performance of the injectors for the liquid fuel-only case.

Several documents are included with this proposal to provide support:

1. DNT Specification 0926 Rev1
2. DNT PID drawing M01
3. DNT drawing Detail 1, showing one form of nozzle penetration
4. DNT drawing Detail 2, showing one other form of nozzle penetration
5. DNT drawing M02, showing a bulk urea storage footprint
6. DNT Project References
7. Colonial Chemical Reagent Price Estimate

**PRICING**

Engineering $75,600

Urea Supply $328,500

ESTIMATED for first year, calculated as 1000 GPD at $0.90/gal, delivered. Note: Urea is an international commodity chemical whose price is usually adjusted quarterly or sooner. This estimate reflects current conditions, which tend to be on the high side of historical trends.

Bulk Storage/Control Mod $126,000
Includes the Storage Tank, and adjacent Control Module (incl. Control Panel)

Distr Panels/Injectors $147,000
Includes the Distribution Panels and the Injector Assemblies

Control Panel $38,000
Also included in Control Module Price.

Commissioning/Start-Up/Training $18,640
Firm price based upon two weeks on-site assistance for installation check-out, start-up supervision, performance optimization, and operator training. Calculated as $1000 per day, plus expenses.

Shipping/delivery $10,000
Estimated total shipping charge for all materials, mostly from New England, to site.

Spare Parts $10,000
Estimated Spare Parts for start-up and first year of operation. Mostly spare injection lances, fuses/bulbs, and pump rebuild kits.

**TECHNICAL SCHEDULE – Case 1 only provided at this time.**

| | | Loadcase Series | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Description** | **Units** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| Nominal Steam Flow | % MCR | 100 | 50 | 100 | 100 | 93 | 100 | 50 | 100 | 50 |
| Urea consumption (in as delivered concentration) | gph | **42.9** | | | | | | | | |
| Dilution water consumption | gpm | **1.33** | | | | | | | | |
| Additional heat load | MMBtu | **By Others** | | | | | | | | |
| Increase in furnace mass gas flow | lb/hr | **1063** | | | | | | | | |
| Furnace exit gas temp. drop | °F | **By Others** | | | | | | | | |
| % Nox reduction | % | **50** | | | | | | | | |
| Controlled Nox at boiler outlet | lb/MMBtu | **0.12** | | | | | | | | |
| Ammonia slip | ppmv | **15** | | | | | | | | |

**UNITED STATES SUGAR COMPANY**
**SNCR SYSTEM**
**DNT SPECIFICATION NO 0926 – Rev 1**

## TABLE OF CONTENTS

## 1.0 INTENT

This specification covers the basic requirements for a urea based SNCR System to be designed and supplied for the US Sugar facility at Clewiston, FL.

## 1.0 REFERENCED STANDARDS

1.1 Reference to the standards of any technical society, organization, or association, or of the laws, ordinances, or codes of governmental authorities shall mean the latest standard code, or specification adopted, published, and effective on the date of the purchase order unless specifically stated otherwise in the contract documents.

1.2 The specifications, codes, and standards referenced below shall govern in all cases where references thereto are made. In case of conflicts between the referenced specifications, codes or standards and these specifications, the latter shall govern to the extent of such differences.

| | |
|---|---|
| AGMA | American Gear Manufacturer's Association |
| AISC | American Institute of Steel Construction |
| ANSI | American National Standards Institute |
| ASTM | American Society for Testing and Materials |
| AWS | American Welding Society |
| IEEE | Institute of Electrical and Electronics Engineers |
| ISA | Instrument Society of America |
| NEC | National Electrical Code |
| NEMA | National Electrical Manufacturers Association |
| NESC | National Electrical Safety Code |
| SSPC | Steel Structures Painting Council |
| NFPA | National Fire Protection Association |

## 2.0 DEFINITIONS

2.1 For the purpose of this Specification, the following definitions and abbreviations shall apply:

2.2 Purchaser: McBurney Boiler Company.

2.3 Vendor: De-NOx Technologies, 22 Partridge Lane, East Hampstead, NH 03826

2.4 Contract: A purchase order placed by the Purchaser with DNT, together with Specifications and all other documents referred to in such purchase order.

2.5 Work: Labor, supervision, services, materials, supplies, machinery, equipment, tools, and facilities called for by the Contract.

2.6 Approved Equal: Products that are considered equal only upon receipt of the Purchaser's written approval.

## 3.0 GENERAL REQUIREMENTS

3.1 The work on this Contract shall commence after DNT has received written Notice to Proceed from the Purchaser. The work shall be executed with sufficient personnel, equipment and material for as many hours per shift and shifts per week as may be required to complete the work in the time stated herein or in the purchase order.

3.2 All Drawings and Documents pertaining to the work shall remain the sole property of DNT and shall not be disclosed by the Purchaser to any third party without prior approval of DNT. Purchaser may provide additional drawings and information to DNT for the purposes of providing additional information, clarifying information already supplied or revising information as required. All such revised and/or additional information is not intended to constitute a change in DNT's Scope of Work, unless it is so designated and so deemed a change in Scope by both the Purchaser and DNT.

3.3 DNT shall furnish the interface details for all electrical, mechanical, and structural interfaces between DNT's Equipment and Purchaser's System. These details shall include as applicable but not necessarily be limited to; physical size, weight, shape, foundation loads, electrical voltage, current, phase(s) and frequency, as well as control interlocks and alarms. DNT shall assist the Purchaser, as required, with the integration of DNT's equipment into the Purchaser's system.

## 4.0 DESIGN CONDITIONS

This system is to be installed on one new 886 MMBTU/hr bagasse fired boiler at Clewiston, FL. The proposed system will utilize 50 wt% liquid urea.

The major design parameters are presented in Table 1.

**TABLE 1**
**Design Conditions per Combustion Unit**

| Design Parameters | Typical |
|---|---|
| Combustor Capacity (MMBTU/hr) | 1 x 886 |
| Oxygen Level (% v) | 3-7 |
| Carbon Dioxide (% v) | 13-19 |
| Carbon Monoxide (ppmdv 3%) | LT 400 |
| Approx Injection Temp (deg F) | 1,800 – 1,950 |
| Min ResidenceTime (sec, prior to | 0.5 |
| first convective surface) | |
| Design Minimum Boiler Load | 50% |
| Uncontrolled $NO_x$ (lb/MMBTU) | 0.24 |
| Controlled $NO_x$ (lb/MMBTU) | 0.12 |
| Ammonia Slip (ppmdv @ 7% $O_2$) | 10 |

5.0 SCOPE OF SUPPLY

DNT will provide the following equipment for the Clewiston facility:

Equipment

- One (1) 15,000 gallon FRP Storage Tank. Based on the information provided and the calculations, this tank will provide a storage capacity of 14 days for the facility operating at 100% load. The approximate dimensions of the tank will be 12' diameter and 18' straight side. The approximate weight of the empty tank will be 4,000 lbs.

  Because of the subtropical nature of the Site, significant capital cost and operational advantages are realized by the elimination of concentrated reagent heating/insulation. If 40 wt% urea solution is used, there will be no risk of crystallization – even well below the ASHRAE 99% dry bulb minimum winter design temperature of 41F. There is a minor operational cost disadvantage hauling extra water to the Site (presumably from the Tampa area), estimated to be approx $15,000 per year. This disadvantage, however, can be eliminated or minimized by purchasing 50 wt% solution during the majority of the year or all year AND on-site dilution when delivered. The storage tank will be filled from 5000 gallon tanker trucks.

The storage tank will also be supplied with:

- Top bolted man way
- Gusseted flanged fittings made of FRP for outlet, fill and instruments.
- Hold Down and Lifting Lugs
- Gooseneck Vent, Drain, Fill Connection, and External Fill Line
- Carbon Steel Ladder, Cage and Handrail, painted safety yellow
- Outlet, Level Indicator, and Drain Isolation Valves
- Level Indicating Transmitter
- Temperature Indicating Transmitter
- Top non-slip surface and UV gel coat protection

- One SNCR Control Module will be supplied. This module will filter and regulate the flow of concentrated reagent and dilution water and mix the two together. The module will be pre-assembled. The Control Module will be located outdoors immediately adjacent to the storage tank. The size of this module is approximately 4' x 6'.

  The module will be equipped with two (2) variable speed, hydraulically actuated, diaphragm pumps (Neptune Series 500 or equal) one operating and one standby. All wetted materials will be constructed of 316 Stainless Steel. The pumps will be equipped with Viton tubular diaphragms. The units will also come equipped with manual stroke adjustment.

  Two (2) duplex strainers of 316 SS construction, capable of continuous filtering of the concentrated reagent and dilution water shall be provided. The device shall be capable of being maintained while on line. Filtering elements shall be constructed of 40 mesh stainless steel screen.

  One local stainless steel NEMA 4X panel will be provided and will include main disconnect, 120 VAC starters, A/B PLC, PLC Power Supply, AI/AO/DI/DO modules, color touch screen HMI, SCR/DC controllers, fuses, motor protectors, panel-front pilot lights/HOA switches, and DH+ interface with the plant's central DCS system. The system shall be capable of full manual operation in case of PLC failure. The Central Control Station shall be capable of monitoring operating parameters and alarm status, as well as remote start/stop. The module's components will be pre-wired and pre-assembled.

The proper amount of reagent is determined based upon boiler load and from CEM system feedback. The metered urea will be introduced into the dilution water line and thoroughly mixed via a SS in-line static mixer. Materials of construction for the concentrated reagent and diluted reagent lines shall be 304 SS tubing, socket welded connections to the maximum extent possible.

- Distribution Panels. Five Distribution Panels shall be provided, located in the closest reasonable proximity to the injection nozzles, each capable of accommodating six injectors. These panels distribute diluted reagent to each injector, as well as control air pressure. Each injector will have local reagent sight flow indication to balance/bias active injectors. These panels can be mounted above handrails of wrap-around platforms, or any convenient wall or column. They measure approximately 3'H x 5W' and weigh less than 500 lbs. From these panels, individual liquid lines are run to each injector.

  The compressed air and liquid flow to each Panel is controlled by MOV's which receive respective signals from the Control Module PLC. The air MOV is provided with a restriction orifice bypass to provide cooling air to idle injectors.

- Dual Fluid Nozzle Atomizing Injectors. The injectors mix the diluted reagent and the atomizing air in the nozzle body outside the boiler. The two-phase fluid then travel down a single, heavy wall, high-alloy tube, terminating 4 - 6 inches inside the boiler. The proprietary injectors have particular advantages:
  - Excellent service life – probably 12 months or better in a bagasse boiler.
  - Non-plugging operation with low quality dilution water
  - Quick connect cam-lock fittings to the boiler mounting tubes, swage-lok fittings to the flexible hose connections, and quick compression-type fittings for easy lance replacement.
  - Short extension outside of the boiler cladding – they can be located in more congested areas.
  - No need for waterwall modifications – can be mounted within a web space as low as ½".

Three separate injection zones are expected based upon the furnace temperature profiles provided in the Request for Proposals. The 100%

load case will be serviced by 6 front wall and 6 rear wall injectors located at elevation 630 inch (above basement) or elev 440 inch above top of grate. The 50 % load case (no aux fuel) will be addressed by a similar zone located at elev 500 inch above basement (306 inch above top of grate), which was selected to be co-located and concentric with the tertiary OFA nozzles. The advantage of integrating the two would be: 1) fewer boiler ports,2) automatic lance cooling when out of service and 3) better furnace penetration/mixing. The third zone would service the LFO case and will be above the 100% load zone, front wall only.

Detail 2 is typical of nozzle penetrations for the wall injectors, detail 1 is a sketch of a proposed arrangement for the zone integrated with the tertiary air system.

Flexible hoses, attached to the injectors with quick connects, will be supplied. The flexible hoses allow for easy removal from the injection port for inspection and maintenance.

Engineering and Start-up Services. These services would include:

- P&ID's, Equipment Arrangement Drawings, mechanical fabrication and assembly drawings, electrical schematic drawings, panel layout, PLC/HMI programming, and bill of materials.
- Specify, select, purchase, prefabricate, and deliver the necessary equipment.
- Civil, Mechanical, and Electrical installation specs
- Mechanical checkout and start-up
- System Optimization.
- Five Maintenance and Operation Manuals.

6.0 PROVIDED BY CUSTOMER

- All receiving and installation.

- Approximately 5 GPM of dilution water @ 80 psig to the Control Module. The quality of the dilution water should meet the following guidelines :

| | |
|---|---|
| Temperature | 50 °F (min) |
| pH | 6-8 |
| Total dissolved solids | 500 ppm (max) |
| Total Hardness as $CaCO_3$ | 200 ppm (max) |
| Total suspended solids | 10 ppm (max) |
| Chlorides | 50 ppm (max) |

- Compressed Air Supply – Normal 150 scfm, design 300 scfm, nominal 100 psig.

- Fused disconnect for 120 VAC power to the Control Module.

- All local permits and/or licenses. DNT will support customer's permitting effort with engineering drawings – stamped by a FL registered PE if necessary.
- Compliance Testing (assumed to be combined with Performance Testing ).

- Hardware/Software interface to Central Control, any additions to Central Control hardware, and Central Control graphics/configuration.

- Adequate trenches, sumps, and drains

- A CEM system capable of measuring NOx, O2, and CO and which meets State and EPA RATA criteria.

- Infrared Furnace Temperature instrument with output to control module PLC.

- Any additional platforms, if any, needed to access the new equipment

## 7.0 PROJECT SCHEDULE

| | |
|---|---|
| Begin Equipment Design | At Notice to Proceed |
| Complete Equipment Design | 10 weeks after NTP |

| | |
|---|---|
| Complete delivery of equipment | 16 weeks after Approvals |
| Typical Mech and Elec Installation | 6-8 weeks after mobilization |

8.0 PERFORMANCE GUARANTEE

8.1 Guarantees

When operating within the design criteria set forth in Table I, DNT guarantees that the outlet $NO_x$ emissions will not exceed 0.12 lbs/MMBTU heat input or 50% reduction, whichever is least stringent. This guarantee will be demonstrated in a Performance Test to be scheduled within 90 days after the equipment is ready for initial operation and testing as determined by DNT. The duration of the Performance Guarantees set forth above shall be for 12 months after successful completion of the Performance Test; 15 months after start up of the equipment; 18 months after substantial completion of erection; or 21 months after substantial completion of delivery, whichever comes first. If such field performance test is not completed within the previously specified 90 day period, through no fault of the Seller, and Purchaser has received from Seller written notice thereof, the Equipment shall conclusively be deemed to meet the stated Performance Guarantee(s). In the event that the operating conditions vary from the Design Conditions given in Table I, the guarantees set forth herein affected by such changed conditions shall be subject to modification and, if the parties mutually agree in writing, the guarantees herein may be appropriately revised.

8.2 Performance Test

- Nitrogen Oxides

  The maximum outlet emission level will be demonstrated by use of the Continuous Emission Monitor by calculating a 24-hour average over a three (3) day time period. Compliance with the guarantee shall be based on the arithmetic average of the hourly emission concentration measured with the CEM system during each day of the three (3) day period, between midnight and the following midnight. The operation of the unit to be tested will be held constant for at least two (2) hours prior to the Performance Test and be at or near the design conditions given in Table 1 throughout the test period. The CEM installation, evaluation and operation shall follow the procedures set forth in 40 CFR 60.13 and shall be operated according to Performance Specification 2 in 40 CFR 60, Appendix B.

- Steady State Conditions

  All testing shall be conducted only at steady state conditions. The boiler and equipment must be at steady state a minimum of two hours prior to testing. Steady state is defined as conditions where flue gas flow rates and temperatures from the boiler do not vary more than +/- 5% and are within design conditions as identified in Table I.

8.3 Guarantee Provisions

The guarantee(s) set forth herein is (are) subject to the following provisions:

- The Equipment supplied by DNT shall be operated and maintained according to DNT's guidelines, good engineering and operating principles and DNT's Operating and Maintenance Manual.

- DNT reserves the right to inspect the Equipment to determine that the operation has been in accordance with DNT's Maintenance and Operation Manual. If required by DNT, the Purchaser will restore the Equipment to good operating conditions before any Performance Tests are conducted.

- DNT will have access to any test records at all times and will have the cooperation of the Purchaser in conducting any preliminary tests that DNT may deem necessary.

- As soon as possible after installation, DNT shall be permitted to conduct preparational tests, at his option, and make adjustments as is necessary to assure that the Performance Guarantee can be fulfilled.

## 9.0 INSTRUMENTATION:

9.1.1 DNT shall furnish all instrumentation and switches required to monitor and control the System as required in this specification and as indicated on the P&ID's.

9.1.2 All instruments shall be factory calibrated and set. Calibration and testing records shall be furnished for all instruments.

9.1.3 DNT shall tag all instrumentation with Purchaser's tag numbers. Instrument numbers will be provided on P&ID's .

9.1.4 DNT shall provide instrument index, listing instrument tag number, description, manufacturer and model number for all instruments. List shall also be provided which indicates the calibrated range of instruments and set points for all switches.

9.1.5 All level transmitters shall be differential pressure type

9.1.6 All instruments to receive manufacture's standard finish paint.

10.0 EQUIPMENT SURVEILLANCE AND TESTING

10.1 All equipment furnished on the purchase order, including auxiliaries, shall be subject to inspection by the Purchaser's and/or Owner's inspection representative. Purchaser's and/or Owner's representative shall be allowed entry into the plant facilities of the manufacturer and its subDNTs and have access to drawings, schedules, inspection reports, material specifications, and tests pertaining to the equipment being furnished on the purchase order.

10.2 Quality Standards and Control shall meet the requirements specified by the Purchase Order.

10.3 PAINTING. CS items will be prepped in accordance with SSPC-6, 3 mil zinc oxide primer, and 3 mil finish coat.

10.4 Specialty items such as motors and variable speed control units, if furnished with the equipment, shall be painted in the shop in accordance with manufacturer's standard practice.

10.5 Before painting, all parts of the equipment shall be thoroughly cleaned of all mill scale, rust, grease, and other foreign matter. All exposed unfinished surfaces of castings shall be properly filled. All welded surfaces shall first be thoroughly cleaned of all alkaline scale, or other deleterious materials that would affect the paint.

10.6 Surfaces shall be thoroughly dry at the time of paint application.

10.7 Chipped, cracked, peeled, or defective paint except where mechanically damaged during shipment, unloading, or erection, shall be replaced at DNT's expense.

## 11.0 SPARE PARTS

DNT shall provide upon completion of design activities, as a separate line item, the spare parts for the equipment required for one year of operation. Spare parts shall be tagged as "Spare Parts" and shipped separate from the equipment. Spare parts supplied shall be suitably wrapped or packaged and tagged with DNT's Part Number.

## 12.0 DRAWINGS AND DOCUMENTS

12.1 General arrangement drawings, including an equipment outline drawing shall show all dimensions, clearances, interfaces, tolerances, foundation loading, anchor bolt requirements, etc.

12.2 All electrical interconnection and wiring diagrams of the equipment, including all variable speed drives (where applicable), control panels, and switches that are furnished with the equipment.

12.3 All drawings shall be clear and legible. Drawings shall be a maximum of 24" X 36" (Size "D" per ANSI 14.1) and shall be to scale where applicable. Equipment general arrangement drawings shall be furnished as CAD drawings in Microstation, or Autocad.

12.4 All words and dimensional units shall be in the English language.

## 13.0 SUBMITTALS

13.1 Drawings and data sheets shall be stamped and returned to DNT as follows:

13.2 APPROVED: Drawings and documents not requiring corrections.

13.3 APPROVED AS NOTED: Drawings and documents shall be corrected and resubmitted immediately as many times as necessary until approved.

13.4 NOT APPROVED: Drawings shall be immediately corrected and resubmitted for approval.

13.5 Equipment shall not be fabricated or delivered prior to DNT receiving approval of drawings/documents from Purchaser unless such approval has been waived in writing.

13.6 All drawings revised after initial submittal, shall be resubmitted with the revised area clearly indicated and revision number and date listed in the title block.

13.7 Identification: All Drawings and Documents transmitted by DNT shall be marked and identified as follows:

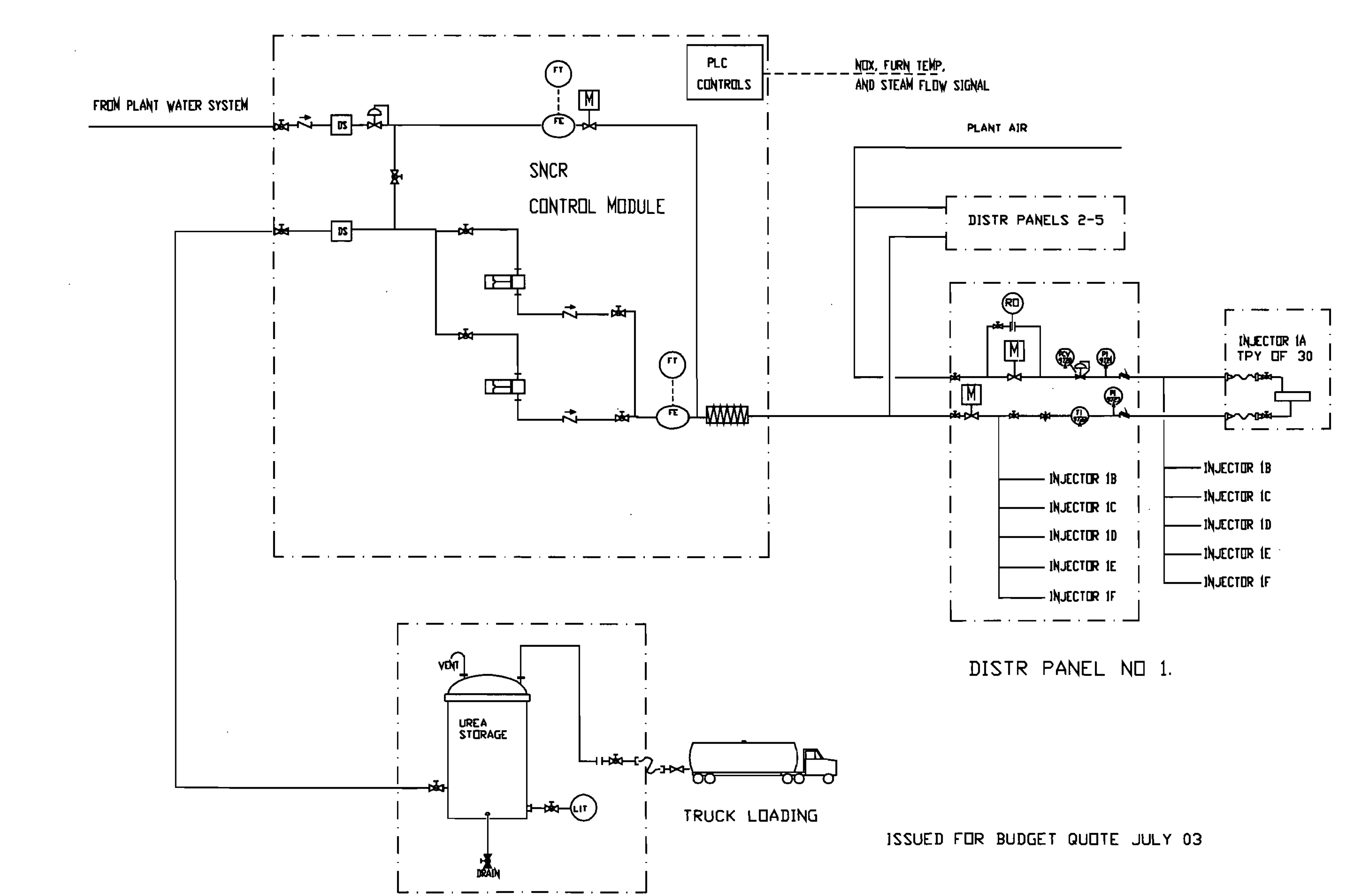
DNT Contract Number (Later)
DNT Specification SPEC-0927
Service: SNCR System
Equipment No.: (Later)

13.8 Mail all Drawings, Data Sheets and Documents with a letter of transmittal to the following address:

Later
Attention: Purchasing Department

13.9 Drawing/Document Transmittal Letter to show the following:

Project Name
DNT Contract Number: Later
DNT's Drawing Number and Title:
Revised Drawings Shall be so Marked and Dated

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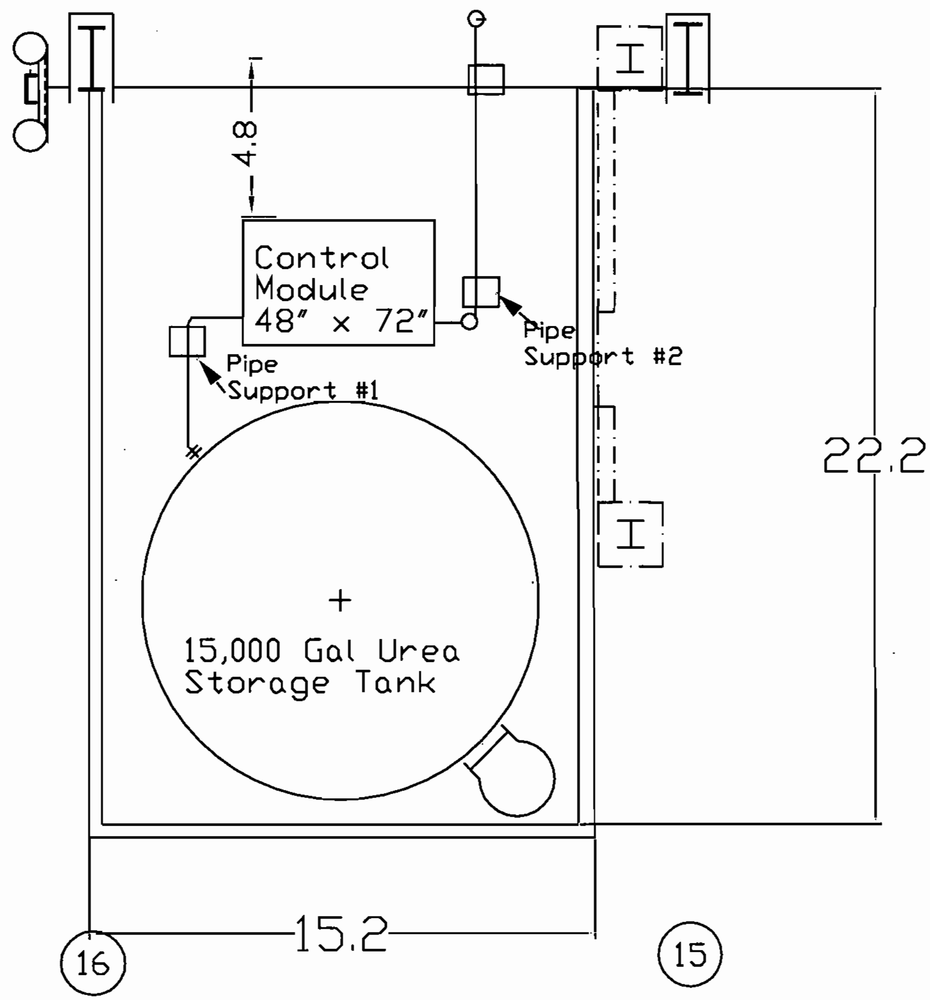
SNCR SYSTEM
US SUGAR COMPANY
PRELIMINARY P&ID

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

M 01 | 0

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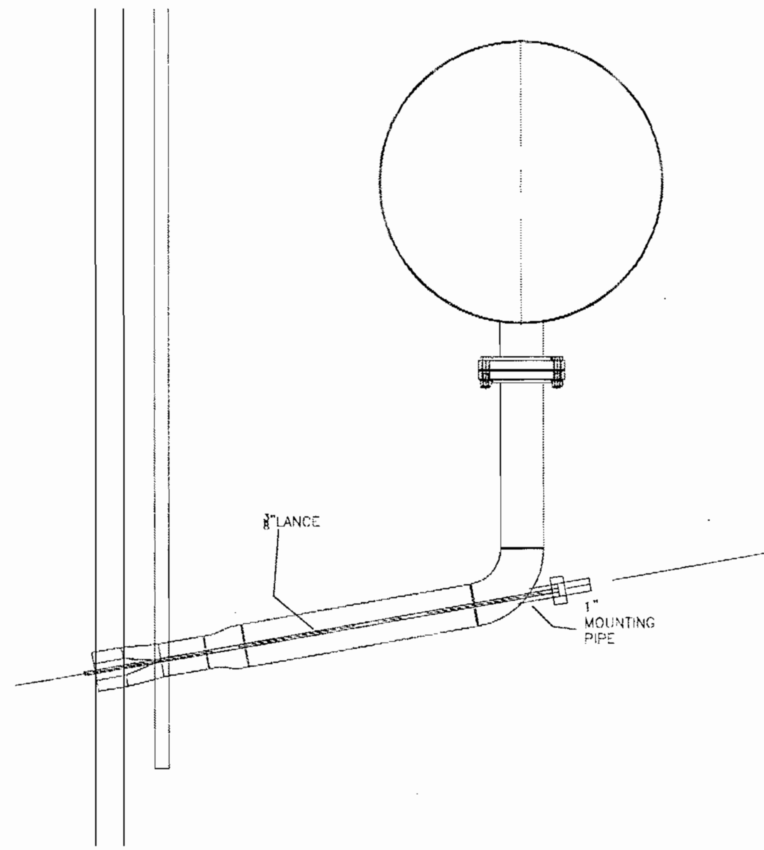
US SUGAR CO
SNCR PROPOSAL
LAYOUT

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

DNT M02 0

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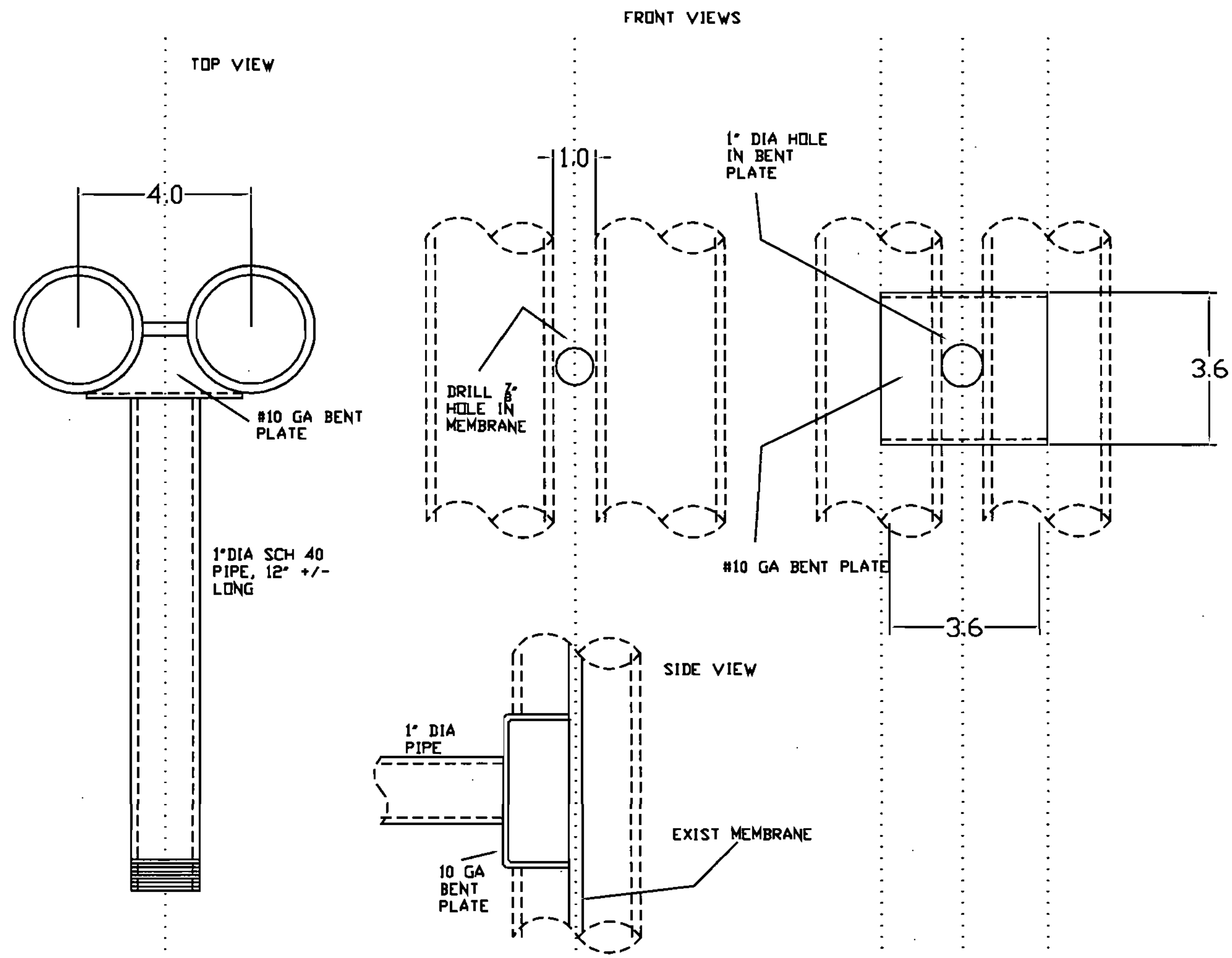
SNCR SYSTEM
US SUGAR COMPANY
INJECTION PORTS

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

DRAWING NUMBER: DETAIL 1 | REV. NO. 0

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US SUGAR
SNCR SYSTEM
INJECTION PORTS

DE-NOX TECHNOLOGIES
EAST HAMPSTEAD, NH

DETAIL 2 | 0

COLONIAL
CHEMICAL
COMPANY

A UNIT OF THE ESS GROUP, INC.
Corrosive Liquids
Formulated & Packaged

July 1, 2003

Mr. David Wojichowski
Managing Director
De Nox Technologies
22 Partridge Lane
East Hampstead, NH 03826

Transmitted by fax - #(815) 301-8450

Dear Dave:

Regarding your request for a forecast of urea costs (40%) to be available in summer of 2004. I would suggest the following price range.

40% liquid urea delivered southeastern Florida region - 1,000 gallon usage/day. {Assuming reasonable stability in the natural gas market ($5 - $6 / MMBTU)}, the average price for 40% liquid would be $.85 - $.95/gallon.

If you have any further questions, please advise.

Very truly yours,

Jim Egan

James T. Egan
President

JTE:kr

78 Carranza Road
Tabernacle, NJ 08088

Tel 609.268.1200
Fax 609.268.2117

De-NOx Technologies, LLC
22 Partridge Lane
East Hampstead, NH 03826
(603) 974-1411
(815) 301-8450 E-fax
dwojichowski@de-nox.com

*DE-NOX TECHNOLOGIES*

# DE-NOX PROJECT REFERENCES

Frackville Dry SNCR Project – Frackville, PA
Scope: Voluntary installation of DNT's proprietary dry SNCR system on a 42 MW Circulating Fluid Bed coal fired boiler. First-of-its-kind installation, designed to generate excess SIP-Call NOX Allowances for profit. Several advantages: 1) Lowest possible capital, 2) Near-negligible chemical costs, 3) No boiler heat rate penalty, and 4) Elimination of boiler tube corrosion risk.

Temple Inland Forest Products – Clarion, PA
Scope: SNCR Optimization Study. Evaluate existing urea SNCR system operation on a wood-fired bubbling bed combustor. Troubleshoot problems and recommend upgrades. Combustor experienced frequent plugging of OEM injectors and marginal NOX reduction. Situation remedied by the supply of new injectors, with superior atomization, and non-clogging internals. Unit operating well with half the number of injectors, longer service life, zero secondary water dilution, and no clogging.

Lihue Energy Services Project – Kauai, Hawaii.
Customer: Innovative Steam Technologies, Cambridge, Ontario
Scope: Design and Supply of a Dry Urea Handling System which creates a urea solution from dry prill delivered in Supersacks for use in a NOX reduction system. Fully shop prefabricated with PLC controls. Accelerated schedule with commercial guarantees.

Martell Cogeneration Facility – Martell, CA
Scope: Process Optimization and equipment upgrades for an existing SNCR system at this 15MW wood fired unit. Unit demonstrated a detached stack plume from excess ammonia slip. Included furnace temperature profiling, dual fluid nozzle supply, and an atomizing air distribution system.

Gloucester County Resource Recovery Facility – Westville, NJ – late 200 and early 2001
Scope: Project Engineer and General Contractor for the installation of an SNCR system and Continuous Emission Monitoring System upgrade. Included the expansion of the compressed air system and the supply of dual fluid injection nozzles to replace the OEM equipment. New nozzles showing much greater service life and 25-30% lower reagent consumption. Design improvements also expected to reduce/eliminate localized corrosion to boiler tubes.

South Broward Resource Recovery Facility – Ft Lauderdale, FL – mid 2000.

Scope: Project Engineer and General Contractor for the installation of an SNCR system at this 90MW refuse to energy facility. Design activities: civil, mechanical, electrical, compressed air addition. Installation activities: bid package development, contractor selection, and construction management.

North Broward Resource Recovery Facility – Pompano Beach, FL – mid 2000

Scope: Same as for South Broward – work nearly identical and executed simultaneously.

Baltimore RESCO – Baltimore, MD - 1999

Scope: Lead Project Engineer and Engineer-of-Record for a large ($40 MM) air pollution control retrofit project, which included expansion of their existing SNCR system.

Westchester RESCO – Peekskill, NY – 1998

Scope: Lead Project Engineer and Engineer-of-Record for a large ($68 MM) air pollution control retrofit project, which included a new SNCR system.

Ridge Generating Station – Lakeland, FL

Scope: Tested generic urea reagents as a substitute for the more expensive, proprietary, reagent. Test was successful leading to a similar conversion at 11 other facilities.

Shasta Energy – Anderson, CA 1989

Scope: Project Engineer for the design and installation of an SNCR system at this 60MW wood fired plant.

Wheelabrator Millbury – Millbury, MA 1986

Scope: Project Engineer for the design, installation, and testing of an SNCR system at this 45MW refuse to energy facility. This was a temporary demo project to test the performance of the system prior to installation elsewhere with commercial and regulatory guarantees. This was the first installation at a large municipal waste-to-energy facility in the US.

## DE-NOX PATENT ASSETS

Three separate US Patent Applications Pending. Technologies address Dry SNCR Processes for several combustion types, external urea-to-ammonia process for SCR reagent supply, and retrofit of existing urea-to-ammonia systems.

# ATTACHMENT B

## REVISIONS TO PERMIT APPLICATION FORM AND PSD REPORT

## Emissions Unit Control Equipment

| | |
|---|---|
| 1. Control Equipment/Method Description (Limit to 200 characters per device or method): | |
| | **Electrostatic Precipitator**<br>**Wet Sand Separator**<br>**Selective Non-Catalytic Reduction for $NO_x$** |
| 2. Control Device or Method Code(s): | **010, 099, 107** |

## Emissions Unit Details

| | | |
|---|---|---|
| 1. Package Unit:<br>Manufacturer: | Model Number: | |
| 2. Generator Nameplate Rating: | MW | |
| 3. Incinerator Information:<br>Dwell Temperature:<br>Dwell Time:<br>Incinerator Afterburner Temperature: | | <br>°F<br>seconds<br>°F |

## G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **$NO_x$** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **288.4** lb/hour **473.7** tons/year | 4. Synthetically Limited? [ **X** ] |
| 5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: **0.14 lb/MMBtu (average)**<br>Reference: | 7. Emissions Method Code: **0** |
| 8. Calculation of Emissions (limit to 600 characters):<br>**Maximum hourly rate: 1,030 MMBtu/hr x 0.28 lb/MMBtu = 288.4 lb/hr**<br>**Annual: 6,767,100 MMBtu/yr x 0.14 lb/MMBtu ÷ 2,000 lb/ton = 473.7 TPY** | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):<br>**Potential emissions representative of bagasse firing. Maximum hourly based on no reduction from SNCR system.** | |

**Allowable Emissions** Allowable Emissions **1** of **2**

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: **0.14 lb/MMBtu, 12 month** | 4. Equivalent Allowable Emissions: **288.4** lb/hour **473.7** tons/year |
| 5. Method of Compliance (limit to 60 characters):<br>**EPA Method 7 or 7E** | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):<br>**Proposed BACT limit. Emissions representative of bagasse firing only.** | |

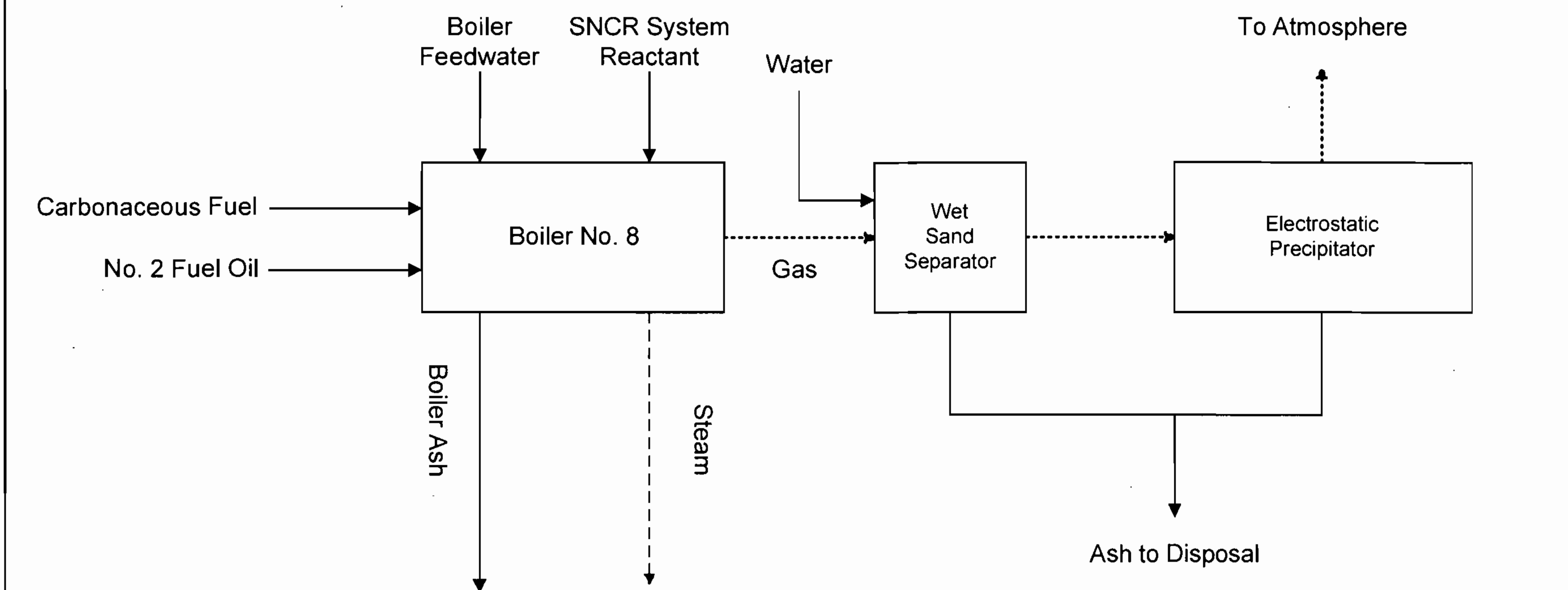
# G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
## (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

**Potential/Fugitive Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **$NO_x$** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: lb/hour tons/year | 4. Synthetically Limited? [ ] |
| 5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year | |
| 6. Emission Factor: Reference: | 7. Emissions Method Code: |
| 8. Calculation of Emissions (limit to 600 characters): | |
| 9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Requested Allowable Emissions and Units: **0.14 lb/MMBtu** | 4. Equivalent Allowable Emissions: **157.36** lb/hour **57.4** tons/year |
| 5. Method of Compliance (limit to 60 characters): **EPA Method 7 or 7E** | |
| 6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Proposed BACT limit. Emissions representative of No. 2 fuel oil firing only. Maximum hourly based on 0.28 lb/MMBtu. Annual emissions based on proposed limit of 6,073,600 gal/yr.** | |




Attachment UC-EU1-J1
Process Flow Diagram
U.S. Sugar Corporation
Clewiston Mill, Florida

**Process Flow Legend**
Solid/Liquid
Gaseous
Steam

Project Number: 0237619\4\4.1\L071803
Filename: UC-EU1-J1.VSD
Date: 7/18/03

Golder Associates

Table 2-2. Maximum Short-Term Emissions for Boiler No. 8, U. S. Sugar Clewiston

| | Bagasse | | | | No. 2 Fuel Oil | | | | Natural Gas | | | | 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) | Emission Factor (lb/MMBtu) | Ref. | Activity Factor (MMBtu/hr) | Maximum Emissions (lb/hr) | Emissions for any fuel (lb/hr) |
| Particulate (Total/$PM_{10}$) | | | | | | | | | | | | | |
| --3-hr Average | 0.026 | (1) | 1,030 | 26.8 | 0.026 | (1) | 562 | 14.61 | 0.0076 | (8) | 562 | 4.27 | 26.8 |
| --24-hr Average | 0.026 | (1) | 936 | 24.3 | | | | | | | | | 24.3 |
| Sulfur Dioxide | | | | | | | | | | | | | |
| --3-hr Average | 0.17 | (2) | 1,030 | 175.1 | 0.05 | (7) | 562 | 28.10 | 0.006 | (8) | 562 | 3.37 | 175.1 |
| --24-hr Average | 0.10 | (2) | 936 | 93.6 | -- | | -- | -- | -- | | -- | -- | 93.6 |
| Nitrogen Oxides | | | | | | | | | | | | | |
| --3-hr Average | 0.28 | (3) | 1,030 | 288.4 | 0.28 | (3) | 562 | 157.36 | 0.28 | (3) | 562 | 157.36 | 288.4 |
| --24-hr Average | 0.28 | (3) | 936 | 262.08 | -- | | -- | -- | -- | | -- | -- | 262.08 |
| Carbon Monoxide | | | | | | | | | | | | | |
| --1-hr Maximum | 6.5 | (4) | 1,030 | 6,695.0 | 0.036 | (10) | 562 | 20.2 | 0.084 | (8) | 562 | 47.208 | 6,695.0 |
| --8-hr Maximum | 4.5 | (4) | 1,030 | 4,635.0 | -- | | -- | -- | -- | | -- | -- | 4,635.0 |
| VOC | 0.06 | (3) | 1,030 | 61.8 | 0.0014 | (10) | 562 | 0.79 | 0.0055 | (8) | 562 | 3.09 | 61.80 |
| Sulfuric Acid Mist | | | | | | | | | | | | | |
| --3-hr Average | 0.0104 | (5) | 1,030 | 10.72 | 0.0015 | (5) | 562 | 0.8430 | 3.68E-04 | (5) | 562 | 0.21 | 10.72 |
| --24-hr Average | 0.0061 | (5) | 936 | 5.73 | -- | | -- | -- | -- | | -- | -- | 5.73 |
| Lead | 3.8E-05 | (6) | 1,030 | 0.039 | 9.0E-06 | (10) | 562 | 5.1E-03 | 5.0E-07 | (8) | 562 | 2.8E-04 | 0.039 |
| Mercury | 1.4E-05 | (6) | 1,030 | 0.0144 | 3.0E-06 | (10) | 562 | 1.7E-03 | 2.6E-07 | (8) | 562 | 1.5E-04 | 0.0144 |
| Fluorides | 6.0E-04 | (7) | 1,030 | 0.618 | -- | | -- | -- | -- | | -- | -- | 0.62 |

References:

1. Proposed BACT limit.
2. 3-hr avg. based on permit limit for Boiler No.7. The 24-hr avg. is based on stack test data for Boiler No. 7.
3. Based on Boiler No. 7 test data.
4. Represents startup or wet fuel conditions.
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.
7. Based on maximum of stack tests from Okeelanta cogen when burning bagasse only.
8. Based on AP-42 Section 1.4 for natural gas combustion:

| | | | |
|---|---|---|---|
| PM (total): | 7.6 lb/$10^6$ scf | VOC: | 5.5 lb/$10^6$ scf |
| $SO_2$: | 0.6 lb/$10^6$ scf | Mercury: | 2.6E-04 lb/$10^6$ scf |
| CO: | 84 lb/$10^6$ scf | Lead: | 0.0005 lb/$10^6$ scf |

9. Based on use of No. 2 fuel oil with a maximum of 0.05% sulfur.
10. 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 2-3. Maximum Annual Emissions for Boiler No. 8, U. S. Sugar Clewiston

| Regulated Pollutant | Biomass Emission Factor (lb/MMBtu) | Ref. | Biomass Activity Factor (MMBtu/yr) | Biomass Annual Emissions (TPY) | Alternate Fuel Emission Factor (lb/MMBtu) | Alternate Fuel Activity Factor (MMBtu/yr) | Alternate Fuel Annual Emissions (TPY) | Total Annual Emissions (TPY) |
|---|---|---|---|---|---|---|---|---|
| | | | | 100% Bagasse | | | | |
| Particulate (Total/$PM_{10}$) | 0.026 | | 6,767,100 | 87.97 | -- | -- | -- | 87.97 [a] |
| Sulfur dioxide[c] | 0.06 | (1) | 6,767,100 | 203.01 | -- | -- | -- | 203.01 [a] |
| Nitrogen oxides[b] | 0.14 | | 6,767,100 | 473.70 | -- | -- | -- | 473.70 [a] |
| Carbon monoxide[b] | 0.38 | (2) | 6,767,100 | 1,285.75 | -- | -- | -- | 1,285.75 [a] |
| VOC | 0.06 | | 6,767,100 | 203.01 | -- | -- | -- | 203.01 [a] |
| Sulfuric acid mist | 0.0037 | (3) | 6,767,100 | 12.43 | -- | -- | -- | 12.43 [a] |
| Lead | 3.8E-05 | | 6,767,100 | 0.13 | -- | -- | -- | 0.13 [a] |
| Mercury | 1.4E-05 | | 6,767,100 | 0.0474 | -- | -- | -- | 0.047 [a] |
| Fluorides | 6.0E-04 | | 6,767,100 | 2.03 | -- | -- | -- | 2.03 [a] |
| | | | | 90% Bagasse / 10% Fuel Oil | | | | |
| Particulate (Total/$PM_{10}$) | 0.026 | | 5,947,164 | 77.31 | 0.026 | 819,936 | 10.66 | 87.97 [a] |
| Sulfur dioxide[c] | 0.06 | (1) | 5,947,164 | 178.41 | 0.05 | 819,936 | 20.50 | 198.91 |
| Nitrogen oxides[b] | 0.14 | | 5,947,164 | 416.30 | 0.14 | 819,936 | 57.40 | 473.70 [a] |
| Carbon monoxide[b] | 0.38 | (2) | 5,947,164 | 1,129.96 | 0.036 | 819,936 | 14.76 | 1,144.72 |
| VOC | 0.06 | | 5,947,164 | 178.41 | 0.0014 | 819,936 | 0.57 | 178.99 |
| Sulfuric acid mist | 0.0037 | (3) | 5,947,164 | 10.93 | 0.0015 | 819,936 | 0.61 | 11.54 |
| Lead | 3.8E-05 | | 5,947,164 | 0.11 | 9.0E-06 | 819,936 | 0.00 | 0.12 |
| Mercury | 1.4E-05 | | 5,947,164 | 0.0416 | 3.0E-06 | 819,936 | 0.00 | 0.0429 |
| Fluorides | 6.0E-04 | | 5,947,164 | 1.78 | -- | -- | -- | 1.78 |
| | | | | 90% Bagasse / 10% Natural Gas | | | | |
| Particulate (Total/$PM_{10}$) | 0.026 | | 5,947,164 | 77.31 | 0.0076 | 819,936 | 3.12 | 80.43 |
| Sulfur dioxide[c] | 0.06 | (1) | 5,947,164 | 178.41 | 0.006 | 819,936 | 2.46 | 180.87 |
| Nitrogen oxides[b] | 0.14 | | 5,947,164 | 416.30 | 0.14 | 819,936 | 57.40 | 473.70 [a] |
| Carbon monoxide[b] | 0.38 | (2) | 5,947,164 | 1,129.96 | 0.084 | 819,936 | 34.44 | 1,164.40 |
| VOC | 0.06 | | 5,947,164 | 178.41 | 0.0055 | 819,936 | 2.25 | 180.67 |
| Sulfuric acid mist | 0.0037 | (3) | 5,947,164 | 10.93 | 3.68E-04 | 819,936 | 0.15 | 11.08 |
| Lead | 3.8E-05 | | 5,947,164 | 0.11 | 5.0E-07 | 819,936 | 0.00 | 0.11 |
| Mercury | 1.4E-05 | | 5,947,164 | 0.0416 | 2.6E-07 | 819,936 | 0.00 | 0.0417 |
| Fluorides | 6.0E-04 | | 5,947,164 | 1.78 | -- | -- | -- | 1.78 |

[a] Denotes maximum annual emissions for any fuel scenario.

[b] Based on 12-month rolling average.

Note: Fuel type percentages are based on heat input.

References:

Unless otherwise note, refer to Table 2-2 for reference.

1. Based on New Hope Power Partnership (Okeelanta Cogen) Permit No. 0990332-014-AC.
2. Equivalent to 363 ppmvd @ 7% O2, as a 12-month rolling average.
3. Based on the $SO_2$ emission factor and 5% conversion of $SO_2$ to $SO_3$ and taking into account the ratio of the molecular weights (98/80).

Table 3-3. Boiler No. 8 PSD Source Applicability Analysis, U. S. Sugar, Clewiston

| | Baseline Emissions [a] | | | | Future Potential Emissions | | | | Net Change In | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Regulated Pollutant | Boiler No. 3 (TPY) | Fugitive Emissions[b] (TPY) | Sugar Refinery (TPY) | Total (TPY) | Boiler No. 8 (TPY) | Fugitive Emissions[b] (TPY) | Sugar Refinery (TPY) | Total (TPY) | Emissions Due to Proposed Project (TPY) | PSD Significant Emission Rate (TPY) | PSD Review Triggered? |
| Particulate Matter (Total) | 48.09 | 2.59 | 13.20 | 63.88 | 87.97 | 12.93 | 21.40 | 122.30 | 58.42 | 25 | Yes |
| Particulate Matter ($PM_{10}$) | 44.48 | 1.65 | 13.06 | 59.19 | 87.97 | 12.07 | 21.40 | 121.44 | 62.25 | 15 | Yes |
| Sulfur Dioxide | 46.81 | -- | 0.75 | 47.56 | 203.01 | -- | 1.25 | 204.26 | 156.70 | 40 | Yes |
| Nitrogen Oxides | 47.72 | -- | 7.87 | 55.59 | 473.70 | -- | 13.14 | 486.84 | 431.24 | 40 | Yes |
| Carbon Monoxide | 1,236.31 | -- | 7.87 | 1,244.18 | 1,285.75 | -- | 13.14 | 1,298.89 | 54.71 | 100 | No |
| VOC | 50.48 | -- | 4.34 | 54.82 | 203.01 | -- | 19.38 | 222.39 | 167.57 | 40 | Yes |
| Sulfuric Acid Mist | 2.87 | -- | 0.046 | 2.91 | 12.43 | -- | 0.077 | 12.51 | 9.60 | 7 | Yes |
| Lead | 0.0076 | -- | -- | 0.0076 | 0.13 | -- | -- | 0.13 | 0.12 | 0.6 | No |
| Mercury | 0.0027 | -- | -- | 0.0027 | 0.047 | -- | -- | 0.047 | 0.045 | 0.1 | No |
| Fluorides | 1.20 | -- | -- | 1.20 | 2.03 | -- | -- | 2.03 | 0.83 | 3 | No |

[a] Actual emissions based on the average emissions for 2001 and 2002.

[b] Represents emissions from bagasse conveying system. See Attachment UC-EU2-G8 and Appendix G for calculations.

TSP = Total Suspended Particles

$PM_{10}$ = Particulate Matter with aerodynamic diameter less than or equal to 10 microns

VOC = Volatile Organic Compounds

# ATTACHMENT C

# REVISIONS TO AIR MODELING ANALYSIS

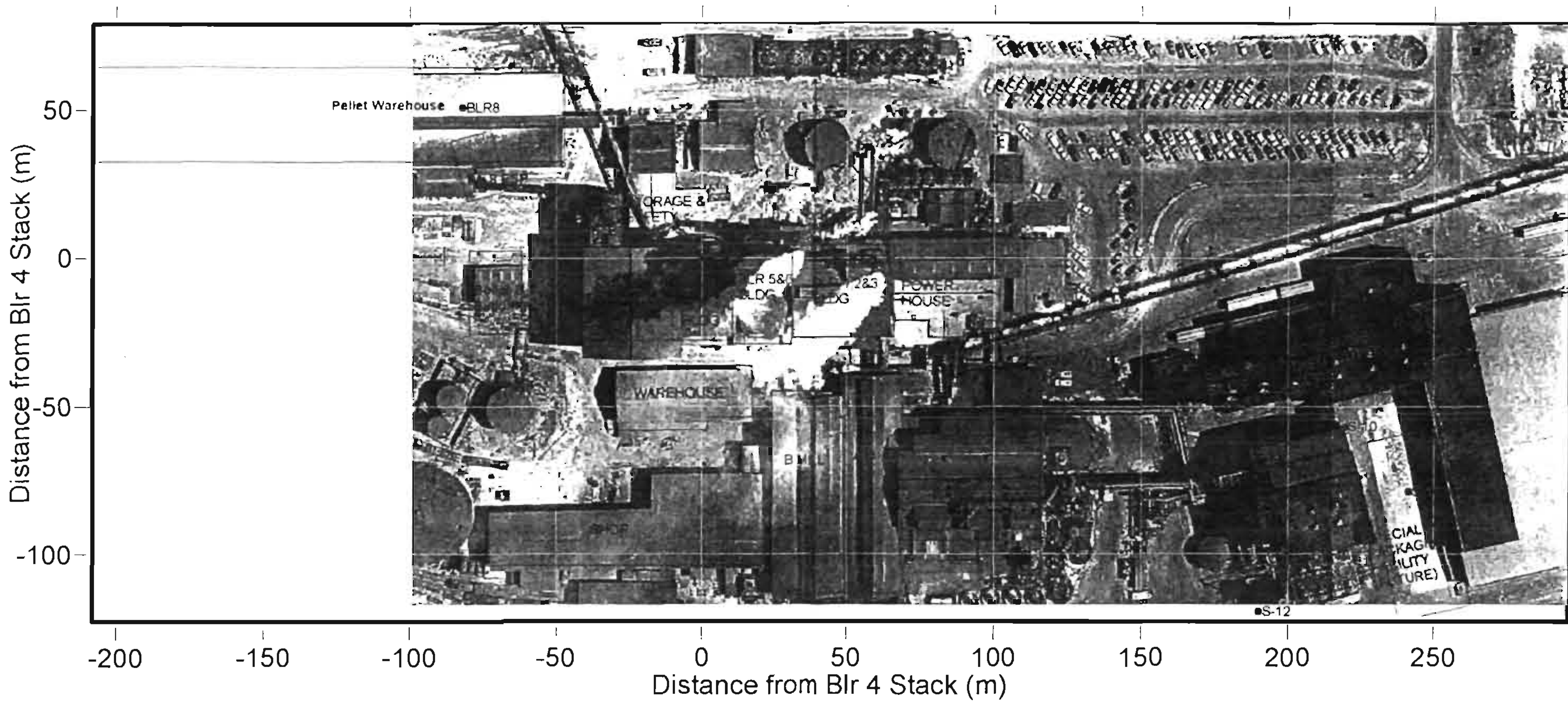

Pellet Warehouse
BLR8
ORAGE &
POWER HOUSE
WAREHOUSE
S-12
Distance from Blr 4 Stack (m)
Distance from Blr 4 Stack (m)
50
0
-50
-100
-200
-150
-100
-50
0
50
100
150
200
250

Table 6-6. Maximum Pollutant Impacts Predicted for the Proposed Project in the Clewiston Mill Vicinity-Screening Analysis with Proposed Boiler No. 8 at 100 Percent Load (Revised July 21, 2003)

| Pollutant | Averaging Time | Concentration[a] ($ug/m^3$) | Receptor Location[b] Direction (degree) | Receptor Location[b] Distance (m) | Time Period (YYMMDDHH) |
|---|---|---|---|---|---|
| $SO_2$ | Annual | 0.08 | 300 | 5,000 | 87123124 |
| | | 0.07 | 300 | 5,000 | 88123124 |
| | | 0.08 | 300 | 5,000 | 89123124 |
| | | 0.09 | 300 | 5,000 | 90123124 |
| | | 0.07 | 300 | 5,000 | 91123124 |
| | 24-Hour | 1.57 | 300 | 7,000 | 87062024 |
| | | 1.65 | 260 | 2,000 | 88061824 |
| | | 1.45 | 330 | 4,000 | 89060924 |
| | | 1.94 | 320 | 4,000 | 90101024 |
| | | 1.83 | 300 | 2,000 | 91072824 |
| | 3-Hour | 14.2 | 170 | 1,800 | 87102612 |
| | | 13.3 | 10 | 2,000 | 88060815 |
| | | 13.7 | 310 | 2,000 | 89071515 |
| | | 11.7 | 120 | 3,000 | 90072809 |
| | | 14.4 | 290 | 1,800 | 91082912 |
| $PM_{10}$ | Annual | 0.77 | 290 | 429 | 87123124 |
| | | 0.96 | 270 | 403 | 88123124 |
| | | 0.87 | 300 | 465 | 89123124 |
| | | 0.97 | 270 | 403 | 90123124 |
| | | 0.89 | 300 | 465 | 91123124 |
| | 24-Hour | 3.79 | 250 | 429 | 87112324 |
| | | 3.95 | 270 | 403 | 88111624 |
| | | 4.89 | 270 | 403 | 89122924 |
| | | 4.25 | 270 | 403 | 90112924 |
| | | 4.34 | 280 | 409 | 91010224 |
| $NO_2$ | Annual | 0.38 | 300 | 4,000 | 87123124 |
| | | 0.33 | 270 | 4,000 | 88123124 |
| | | 0.40 | 300 | 4,000 | 89123124 |
| | | 0.45 | 300 | 4,000 | 90123124 |
| | | 0.43 | 300 | 4,000 | 91123124 |
| CO | 8-Hour | 203 | 220 | 1,500 | 87053016 |
| | | 198 | 260 | 2,000 | 88061816 |
| | | 196 | 310 | 2,000 | 89071516 |
| | | 176 | 310 | 2,000 | 90052816 |
| | | 224 | 310 | 2,000 | 91072416 |
| | 1-Hour | 1,017 | 320 | 900 | 87072711 |
| | | 1,036 | 310 | 900 | 88072611 |
| | | 1,017 | 260 | 1,200 | 89081111 |
| | | 1,064 | 300 | 900 | 90070112 |
| | | 1,013 | 350 | 900 | 91061611 |

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Based on the 5-year meteorological record from the National Weather Service station in West Palm Beach, 1987 to 1991.

[b] Relative to Boiler No. 4 Stack Location.

Table 6-7. Maximum Pollutant Impacts Predicted for the Proposed Project in the Clewiston Mill Vicinity-Screening Analysis with Proposed Boiler No. 8 at 80 Percent Load (Revised July 21, 2003)

| Pollutant | Averaging Time | Concentration[a] (ug/m$^3$) | Receptor Location[b] Direction (degree) | Receptor Location[b] Distance (m) | Time Period (YYMMDDHH) |
|---|---|---|---|---|---|
| $SO_2$ | 24-Hour | 1.49 | 300 | 5,000 | 87062024 |
| | | 1.58 | 260 | 2,000 | 88061824 |
| | | 1.40 | 330 | 4,000 | 89060924 |
| | | 1.90 | 320 | 3,000 | 90101024 |
| | | 1.76 | 300 | 2,000 | 91072824 |
| | 3-Hour | 13.8 | 170 | 1,500 | 87102612 |
| | | 12.6 | 10 | 1,800 | 88060815 |
| | | 13.1 | 170 | 1,800 | 89102612 |
| | | 10.7 | 270 | 1,800 | 90070712 |
| | | 13.8 | 290 | 1,500 | 91082912 |
| $PM_{10}$ | 24-Hour | 3.79 | 250 | 429 | 87112324 |
| | | 3.95 | 270 | 403 | 88111624 |
| | | 4.89 | 270 | 403 | 89122924 |
| | | 4.25 | 270 | 403 | 90112924 |
| | | 4.34 | 280 | 409 | 91010224 |
| CO | 8-Hour | 196 | 220 | 1,500 | 87053016 |
| | | 188 | 260 | 1,800 | 88061816 |
| | | 190 | 310 | 2,000 | 89071516 |
| | | 171 | 310 | 2,000 | 90052816 |
| | | 225 | 290 | 3,000 | 91052124 |
| | 1-Hour | 866 | 360 | 600 | 87091812 |
| | | 908 | 310 | 900 | 88072611 |
| | | 831 | 260 | 1,200 | 89081111 |
| | | 912 | 320 | 900 | 90080511 |
| | | 913 | 360 | 900 | 91073114 |

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Based on the 5-year meteorological record from the National Weather Service station in West Palm Beach, 1987 to 1991.

[b] Relative to Boiler No. 4 Stack Location.

Table 6-8. Maximum Pollutant Impacts Predicted for the Proposed Project in the Clewiston Mill Vicinity- Refined Analysis for Comparison to the PSD Class II Significant Impact Levels (Revised July 21, 2003)

| Pollutant | Averaging Time | Boiler No. 8 Operating Load | Concentration (ug/m$^3$) | Receptor Location[a] Direction (degree) | Receptor Location[a] Distance (m) | Time Period (YYMMDDHH) | Significant Impact Level (ug/m$^3$) |
|---|---|---|---|---|---|---|---|
| $SO_2$ | Annual | 100 | 0.09 | 299 | 5,000 | 90123124 | 1 |
| | 24-Hour | 100 | 2.32 | 323 | 3,800 | 90101024 | 5 |
| | | 80 | 2.22 | 323 | 3,400 | 90101024 | |
| | 3-Hour | 100 | 14.6 | 289 | 1,700 | 91082912 | 25 |
| | | 80 | 13.9 | 289 | 1,600 | 91082912 | |
| $PM_{10}$ | Annual | 100 | 0.96 | 270 | 403 | 88123124 | 1 |
| | | 100 | 0.97 | 270 | 403 | 90123124 | |
| | 24-Hour | 100 | 4.89 | 270 | 403 | 89122924 | 5 |
| | | 80 | 4.89 | 270 | 403 | 89122924 | |
| $NO_2$ | Annual | 100 | 0.45 | 300 | 4,100 | 90123124 | 1 |
| CO | 8-Hour | 100 | 245 | 308 | 2,100 | 91072416 | 500 |
| | | 80 | 233 | 308 | 1,900 | 91072416 | |
| | 1-Hour | 100 | 1,183 | 301 | 800 | 90070112 | 2,000 |
| | | 80 | 1,039 | 301 | 800 | 90070112 | |

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Relative to Boiler No. 4 Stack Location.

# Department of
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary


June 16, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: **Request for Additional Information - Reminder**
Project No. 0510003-021-AC (PSD-FL-333)
Clewiston Sugar Mill and Refinery
Proposed New Boiler 8

Dear Mr. Raiola:

On May 22, 2003, the Department received additional information regarding your application for an air permit, which proposes to construct a new 1031 MMBtu/hour boiler to support operations of the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. On May 28, 2003, the Department met with representatives of U.S. Sugar in Tallahassee to discuss remaining information necessary to complete the application, which included the following general items:

- Revised air quality analysis for the corrected site plan and potential changes to downwash impacts;
- Revised emission profile for the proposed boiler with potentially higher uncontrolled NOx rate and lower CO/VOC rates;
- SNCR details including NOx and ammonia performance guarantees (discussed estimated equivalent range for NOx standard between 0.11 – 0.14 lb/MMBtu for a 30-day rolling average and 10 – 15 ppm ammonia slip);
- Additional details for the alternate sampling procedure for opacity including critical ESP parameters and supplementary monitoring (similar to a "CAM" plan);
- Discussion/recommendation of excess emissions ranges and permit conditions;
- Requested gaseous emission standards in terms of "ppmvd @ 3% oxygen" (standards in terms of "lb/MMBtu" would be listed for informational purposes);

This is a reminder that the application remains incomplete. In order to continue processing your application, the Department will need the additional information listed above and discussed at the May 28th meeting. 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 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. now 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
New Source Review Section

cc: Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

**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
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

**COMPLETE THIS SECTION ON DELIVERY**

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6/18/03

C. Signature X [signature] ☐ Agent ☐ Addressee

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. 7001 0320 0001 3692 5764

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

**U.S. Postal Service**
**CERTIFIED MAIL RECEIPT**
*(Domestic Mail Only; No Insurance Coverage Provided)*

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7001 0320 0001 3692 5764

| | | |
|---|---|---|
| Postage | $ | Postmark Here |
| Certified Fee | | |
| Return Receipt Fee (Endorsement Required) | | |
| Restricted Delivery Fee (Endorsement Required) | | |
| **Total Postage & Fees** | $ | |

*Sent To* William A. Raiola
*Street, Apt. No.; or PO Box No.* 111 Ponce DeLeon Ave.
*City, State, ZIP+4* Clewiston, FL 33440

PS Form 3800, January 2001 See Reverse for Instructions

**Golder Associates Inc.**

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

RECEIVED
MAY 22 2003
BUREAU OF AIR REGULATION

May 21, 2003

0237619

Florida Department of Environmental Protection
Department of Air Resources Management
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Attention: Mr. Jeffery Koerner, P. E.

RE: United States Sugar Corporation (U.S. Sugar) – Clewiston Mill
Proposed New Boiler No. 8
DEP Project No. 0510003-021-AC (PSD-FL-333)

Dear Mr. Koerner:

U. S. Sugar is in receipt of the Department's request for additional information (RAI) dated April 25, 2003, for the above referenced project. The project is for the proposed primarily bagasse-fired Boiler No. 8, a new 550,000 lb/hr steam. Responses to each of the Department's requests are provided below, in the same order as they appear in the letter.

1. **Boiler No. 8**

The bagasse feed rate and the boiler heat input rate will be determined consistent with standard practice in the sugar industry. The boiler heat input rate will be determined by continuously measuring steam production rate, steam pressure and temperature, and feedwater temperature. Using the steam enthalpies and the design thermal efficiency of 62 percent, the heat input rate will be determined. The bagasse feed rate will be calculated based on the heat input rate and the average bagasse heating value for the Clewiston mill of 3,900 Btu/lb (wet basis).

The fuel-air ratio will be controlled by adjusting the primary (undergrate) and secondary (overfire) airflow to the boiler. The master pressure controller output signal will pass through a predefined ratio station, which then becomes the setpoint for the airflow controllers. The airflow signal is then trimmed by the oxygen controller, which trims the airflow to a predetermined oxygen level. The oxygen content of the flue gas will be measured in the boiler outlet duct prior to the airheater to ensure that the flue gas reading is not affected by dilution from tramp air. The setpoint of the oxygen controller will vary with load and fuel quality. The operator will also be able to manually adjust the air flow to address situations where the fuel may be very wet, in order to maintain steam rate, maintain proper combustion conditions, and control CO and opacity.

The sootblower design has not yet been finalized, but it is likely that the following sootblowers will be fitted to the boiler:

- Two retractable blowers between the primary and secondary superheaters.
- Two retractable sootblowers between the secondary superheater and the mainbank.
- Two fixed rotary blowers in the centre of the mainbank.
- Four rake type sootblowers – one above each economiser bank.

It is anticipated that the sootblowers will be used once every 8-hour shift. The sequence will be from the front of the boiler towards the rear of the boiler, i.e., from the primary superheater to the economizer. The duration of sootblowing will be approximately 30 to 45 minutes. It is anticipated that opacity and particulate emissions will increase during the operation of the sootblowers. However, it is not possible to quantify the magnitude of emissions during this time.

The normal operating range of the flue gas oxygen will be dependent upon boiler load, the quality of the fuel, and the type of fuel.

- Under normal sugar mill operating conditions, the boiler exit $O_2$ is expected to be between 3.0 and 4.0%. High fuel moisture, high ash content and low load conditions could result in the boiler exit $O_2$ increasing to 5.0 to 6.0%.
- The boiler exit $O_2$ while firing only fuel oil will range between 8.0 and 9.0%. This is because of the tramp air required for cooling of the stoker, pneumatic distributors, and overfire air nozzles during fuel oil firing.
- The stack $O_2$ for both cases could be 1 to 2% higher depending on the amount of ambient air infiltration there is across the system.

During the milling off-season, Boiler No. 8 is expected to be the primary boiler used to support the refinery. Boiler Nos. 7 and 8 will not normally operate at the same time during the off-season. However, Boiler Nos. 4 and 7 could operate at the same time in the off-season, when Boiler No. 8 is off-line.

2. **Requested Fuels**

U. S. Sugar will install dual-fuel burners in Boiler No. 8, capable of burning either No. 2 fuel oil or natural gas. However, natural gas is not yet available at the site. Therefore, U. S. Sugar will agree to not pursue the gas option at this time. The permit should recognize the dual-fuel capability of the burners.

3. **Requested Capacity Restrictions**

Comment is acknowledged. Note that PSD applicability review as if the boiler were not yet constructed would only apply to those pollutants for which PSD review was originally avoided. PSD applicability for pollutants undergoing PSD review for the original construction permit would be based on the PSD requirements for modifications to existing sources.

4. **CO and VOC Emissions**

As shown in Appendix A, Item 5.E of the application, the calculation of mass CO emissions was based on 363 ppmvd @ 7 percent $O_2$. Therefore, to perform the calculation, the gas flow rate must first be corrected to 7 percent $O_2$. The ppm concentration and the flue gas flow rate must both be corrected to the same oxygen level.

The proposed CO emission rate for Boiler No. 8 is 356 lb/hr at the maximum heat input rate of 936 MMBtu/hr, which equates to 0.38 lb/MMBtu. This emission rate is believed to be achievable on a 12-month rolling average basis, and also nets out of PSD review. CO emissions in terms of ppm were provided only because the proposed MACT standard is in these terms. The proposed maximum mass CO emission rate of 356 lb/hr or 0.38 lb/MMBtu does not vary as a function of flue gas oxygen. However, the calculated ppmvd concentrations will change as the flue gas oxygen level changes. The flue gas concentrations shown in Appendix A are at 3 percent and 7 percent $O_2$, for informational purposes.

As shown in Appendix A of the application, the proposed annual CO limit of 0.38 lb/MMBtu is equivalent to 467 ppmvd @ 3 percent $O_2$. Therefore, at 400 ppmvd, the limit would become 0.325 lb/MMBtu (0.38 x 400/467) and 305 lb/hr.

As demonstrated in the application, meeting a CO limit of 400 ppmvd on a 24-hour average basis is not achievable for a bagasse boiler. We would agree to the proposed limit of 363 ppmvd @ 7 percent $O_2$ (equivalent to 467 ppmvd @ 3 percent $O_2$) as being a target level on a 1-hour average, in the same way that the CO monitor is used on Boiler No. 4 at Clewiston, i.e., as a trigger level for corrective action.

Although a VOC limit of 0.03 lb/MMBtu may be achievable under best circumstances, it may not be achievable at all times, considering the nature of the bagasse fuel. An emission limit must be met at all times, excluding startup, shutdown and malfunction. Note that the proposed 12-month rolling average CO limit is 0.38 lb/MMBtu; therefore, higher short-term levels of CO emissions are expected to occur. VOC emissions are expected to vary in a similar manner.

As the Department correctly notes, Boiler No. 7 test data showed VOC emissions of 0.11 lb/MMBtu at a CO emission rate of 0.39 lb/MMBtu. Although this test may not reflect the best combustion conditions, this is the nature of bagasse fuel. Higher moisture fuel can and does occur at times. Boiler No. 7's VOC emission limit is 0.212 lb/MMBtu, so this test was not a violation, but would have been if the limit were 0.03 or 0.06 lb/MMBtu. While Boiler No. 8 may produce lower VOC emissions than Boiler No. 7, absent actual operating data, it is difficult for U. S. Sugar to accept a VOC limit of less than 0.06 lb/MMBtu at this time, given the nature of bagasse fuel. The proposed limit is consistent with the recently issued PSD permit for Palm Beach Power Corporation and New Hope Power's current permit limit. The proposed limit is more than three times lower than the current limit for Boiler No. 7.

The VOC test data for Boiler No. 7, provided in Appendix D of the application, does not include methane/ethane. As noted in the VOC column title, the VOC emissions were determined using EPA Methods 25A and 18. Method 18 was used to determine methane content, which was then subtracted from the Method 25A results, to provide non-methane VOC.

5. **Particulate Matter Controls**

**Wet Cyclone:** To protect the ID fan from abrasion, two low efficiency non-saturating wet cyclones will be installed in parallel. The attached sketch 1/49-999-026 shows the layout of one of the units. Gas enters the cyclone through a venturi throat. The area of the throat is manually adjustable. Spray nozzles are incorporated in the throat.

After leaving the venturi, the gas spirals upwards through the vessel. Coarse abrasive ash particles adhere to the periphery, from where they are washed down to the discharge hopper. The hopper has two outlets: a normal outlet and an emergency outlet. The latter is used in case the normal outlet blocks. The pressure drop across the wet cyclone will be about 4" w.g. at maximum load.

Gas leaves the wet cyclone through a port at the top of the vessel, and is ducted to the ID fan inlet. Each cyclone will be designed to handle approximately 191,000 acfm. The two cyclones will require a total of approximately 400 to 500 gallons per minute (gpm) of water.

The expected wet cyclone collection efficiency is as follows:

| Particle size (um) | Collecting efficiency |
|---|---|
| 5 | 3% |
| 30 | 30% |
| 100 | 85% |

No inlet/outlet testing has been conducted on the wet cyclone installed on Boiler No. 7.

**ESP:** Currently, budgetary proposals are being solicited from the following ESP suppliers:

Environmental Elements Corporation
Baltimore, MD, USA

PPC Industries
Longview, TX, USA

FL Smidth - Air Tech Inc.
Houston, TX, USA

It is intended to expand this list to include other qualified suppliers when firm price bids are requested. The ESP will be a dry, negative corona plate ESP. Please see Table 1 (page 9 of this letter), which presents data taken from preliminary ESP vendor proposals.

The final ESP selected will have multiple T-R sets. Also, the final selected unit may not have nine fields.

The following description of the rapping system used to remove ash from the ESP is taken from one of the budgetary ESP quotations:

> The electric impulse rapper has been specifically designed for rapping the collecting surfaces, discharge electrodes and perforated distribution plates. The rappers are the single impulse gravity impact type consisting of an integral DC coil and steel housing assembly, a 20-lb piston and mounting hardware.
>
> Rapper impact is precisely repeatable. Intensity of impact and frequency of operation are controlled by a microprocessor-based controller.
>
> Trough type hoppers are fabricated from 3/16 inch ASTM A-36 steel with external stiffeners of uniform depth to provide support for thermal insulation and siding. The hoppers are designed to support full dust load. The sides and ends are sloped 60° and 75°, respectively, from the horizontal. The valley angle resulting from this design is 57.5°. The between field baffles are extended to the hopper outlet to eliminate gas bypassing in the hoppers. Each hopper is provided with high-level alarms, electric resistance heating elements, strike plates for manual rapping. Hoppers should not be used for storage.

The main parameter for the ESP during startup is gas temperature. Gas temperature entering the ESP should be at 300°F or higher for a minimum of 10-minutes before the ESP is energized. This is necessary to allow any condensation on the ESP internals (plates, rods, etc) to dry out before the unit is energized. This practice prevents wet dust on the plates from sealing and fouling the plates.

The boiler design and the warm-up curve dictate the elapsed time from initial fuel firing. Standard practice is to limit boiler warm-up to no more than 100° per hour (boiler water temperature). It is expected that it will take approximately 4-6 hours to achieve a flue gas temperature of 300°F.

**COMS:** Our justification for the Alternate Sampling Procedure (ASP) for opacity, requested in lieu of the continuous opacity monitoring system (COMS) required by NSPS Subpart Db, is that Boiler No. 8 will be operated infrequently on fuel oil. The annual capacity factor on fuel oil will be limited to 10 percent. EPA has issued approval of numerous ASPs for Subpart Db boilers that have limited their annual fuel oil capacity to 10 percent or less.

U. S. Sugar would oppose the use of a COMS, based on the fact that there is no demonstrated correlation between opacity and mass emissions for fuel combustion sources. Also consider that the CAM requirements (40 CFR Part 64) will ultimately apply to Boiler No. 8 for PM emissions. At that time, U. S. Sugar will be required to propose indicator parameters and develop parametric ranges for those parameters.

6. **Sulfur Dioxide and Sulfuric Acid Mist Controls**
While there is not much difference between the Department's suggested $SO_2$ emission limit of 0.05 lb/MMBtu for bagasse firing, there is also no evidence to suggest a limit less than 0.06 lb/MMBtu is achievable. Only one $SO_2$ test is available from the sugar industry for a bagasse boiler controlled with an ESP (U. S. Sugar Boiler No. 7). The proposed limit is based on the recently issued PSD permit for Palm Beach Power Corp, and the current permit limits for U. S. Sugar Boiler No. 4 and New Hope Power. It is about three times lower than the current $SO_2$ limit for Boiler No. 7 of 0.17 lb/MMBtu.

$SO_2$ control is inherent to the bagasse combustion process. U. S. Sugar will not have control over the inherent removal mechanisms. If the Department sets a lower $SO_2$ standard, it should allow revisiting of the standard if further test data indicate that the standard is too low.

7. **Controls for Nitrogen Oxides**
The proposed Boiler No. 8 is neither a coal-fired boiler nor a municipal waste combustor. There are constituents in sugarcane and the resulting bagasse fuel that lead to severe catalyst poisoning, making conventional SCR infeasible. To determine the feasibility of SCR, site-specific ash analysis and boiler data was provided to catalyst manufacture Haldor Topsoe. U. S. Sugar obtained an ESP ash sample from Boiler No. 7. The sample was sent to the lab for analysis. The results are shown in Attachment A, along with published analysis for coal. As shown, the potassium, sulfur trioxide, and phosphorus content of the ash was very high compared to coal ash. The bagasse ash also showed high levels of chlorine.

Flemming Hansen of Haldor Topsoe responded with the following statement:

> "We have looked at the data you sent and notice that the content of K in the ash is 10%, which is twice as much as we observed in a testing on the wood fired boiler. In addition the content of Cl is > 5%. Thus a very large amount of KCl aerosols (a severe catalyst poison) is to be expected, which will result in a very rapid deactivation in a high dust position. I will expect that the deactivation will be so high, that it is not manageable in practice."

Based on Haldor Topsoe's site-specific determination, SCR placed directly after the boiler should be considered infeasible for this project.

There currently is no experience of SCR installations on bagasse-fired boilers. However SCR has been placed on MSW units in a "tail-end" configuration. This type of installation allows the SCR to be placed downstream of all other pollution controls, minimizing the chance of severe catalyst degradation or fouling due to the ash constituents. Although MSW and bagasse fired boilers do not produce similar ash, they both have the potential of catalyst poisoning and therefore "tail-end" SCR is feasible for bagasse-fired boilers. It should be noted that, as with conventional SCR, there is no experience of "tail-end" SCR installations on bagasse-fired boilers.

A cost analysis for "tail-end" SCR was prepared based on a recent cost quote from Hamon Research-Cottrell for a similar sized bagasse fired boiler. The cost quote assumed a SCR operating temperature of 700 degrees F. Therefore, the annual cost includes the cost associated with reheating the flue gas from 330 to 700 degrees F. The reheat costs are based on No. 2 fuel oil, since natural gas is currently not available at the facility.

The "tail-end" SCR cost analysis is presented in Attachment B. Based on the vendor quote and the OAQPS Cost Control Manual, the total capital cost of "tail-end" SCR for Boiler No. 8 is estimated at $5.2 million. The total annualized cost of applying "tail-end" SCR is estimated at $7.05 million per year. The resulting cost effectiveness is $11,840 per ton of $NO_x$ removed. Therefore, "tail-end" SCR is considered to be economically infeasible for Boiler No. 8.

It is noted that this does not include the additional pollutant emissions caused by the reheat system. Additional $NO_x$ emissions associated with such a system are estimated at 52 TPY or higher. The cost effectiveness would increase to over $13,000 per ton considering these additional $NO_x$ emissions.

**SNCR:** As discussed in the application, our primary concerns surrounding SNCR are the potential effects on boiler operation due to ammonia slip and ammonium bisulfate formation on the downstream boiler components. The former Osceola Power L. P. facility experienced severe superheater tube failures associated with increased urea injection to meet its $NO_x$ emissions limit. SNCR has never been applied to a purely bagasse-fired boiler. The bagasse fuel characteristics and combustion characteristics are much different than wood or wood/bagasse firing. The effects of the increased moisture in the flue gas and other constituents in the ash (sulfur, potassium, chlorine, phosphorus, etc.) may have a yet unknown and unpredictable effect upon boiler components. As demonstrated is separate proceedings, the boilers at the Clewiston Mill are already subject to increased wear, corrosion and erosion due to fuel constituents. The use of SNCR could compound these problems.

We ask that the Department reconsider its position on SNCR. The Clewiston mill is located in a remote, rural area, where $NO_x$ emissions are less likely to contribute to high ozone levels in the populated urban areas. The already low proposed NOx emissions rate of 0.22 lb/MMBtu does not warrant further reduction.

**$NO_x$ CEMS:** Previous $NO_x$ testing on bagasse boilers has indicated $NO_x$ emissions do not vary greatly, due to the high moisture content of the fuel, which suppresses $NO_x$ emissions. Test results from Boiler No. 7 at Clewiston confirm this. There does not appear to be any requirement or need for a $NO_x$ CEMS.

8. **Boiler MACT**
Based on the Department's position, there is no reason a the present time to require that Boiler No. 8 meet the MACT, since the MACT will apply regardless of whether it is included in the construction permit. In addition, neither the final form of the MACT nor the emission limits are known at this time. Further, the final MACT rule could exempt non-major new sources from the MACT requirements. Therefore, it would be premature and speculative to require the boiler to meet the limits in the proposed MACT standard. The final standards could be totally different than those proposed. The Department should accept U. S. Sugar's proposed CO limit of 0.38 lb/MMBtu, which avoids PSD review and therefore exempts the proposed boiler from BACT.

9. **Bagasse Handling System**
Refer to Section 2.4 of the PSD report. U. S. Sugar had previously permitted six (6) bagasse handling system dust collectors as part of a modification of the bagasse handling system (refer to permit no. 0510003-011-AC). With Boiler No. 8, and associated revisions to the system, there will now only be five (5) dust collectors. The grain loadings, air flow rates, and control efficiencies of the dust collectors are shown in the footnotes to Attachments UC-EU2-G and UC-EU2-J3 of the application form. In essence, one of the previously permitted dust collectors has been eliminated.

10. **Refinery Operations**
U. S. Sugar is not requesting any changes to existing permit limits for the refinery. However, due to the potential increase in actual refinery operation due to Boiler No. 8, the increase in emissions has been quantified, as described in Section 3.5.2 and shown in Table 3-3 of the PSD report.

11. **CAM Plan**

Comment is acknowledged.

12. **Air Quality Modeling Review**

U. S. Sugar has received the Department's letter dated May 2, 2003, concerning the air quality modeling analysis. Two comments were contained in the letter, and are both addressed below.

A. Attached is the requested drawings. Building data from the BPIP file were overlaid on an aerial of the mill. These BPIP data were used in previous air modeling analyses for the mill. As shown in the figure, the buildings used in the model are generally aligned with those shown in the aerial. Any differences are expected to produce minimal, if any, differences in predicted concentrations. It should be noted that the pellet warehouse was modeled as it exists, even thought the eastern portion of the warehouse will be removed once Boiler No. 8 is constructed. Since the height of the warehouse is relatively low compared to Boiler No. 8's stack, it does not have an effect on building downwash effects for that stack.

B. Additional information regarding the air quality impacts of general commercial, residential, industrial and other growth that has occurred in the area since August 7, 1977, please refer to Attachment C.

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13. **Comments from EPA or NPS**
We have not received any comments from EPA as of this date. Comments from the National Park Service (NPS) are addressed in the following.

**$NO_x$ BACT:** U. S. Sugar Clewiston Boiler No. 4 test data demonstrated an average uncontrolled NOx emissions rate of 0.08 lb/MMBtu. However, this boiler was originally built as a coal-fired boiler in the 1950's and moved to Clewiston and converted to bagasse firing in1985. Therefore, its NOx emissions are not representative of a modern bagasse-fired boiler. Uncontrolled $NO_x$ emissions of 0.22 to 0.26 lb/MMBtu are representative of a modern bagasse-fired boiler (reference Clewiston Boiler No. 7 and New Hope Power Partnership). The higher $NO_x$ emissions are a result of better combustion of the fuel, which also results in lower CO, VOC and organic HAP emissions. U. S. Sugar has specified a $NO_x$ limit on the lower end of this range in an attempt to force the boiler vendors to design to the lowest achievable $NO_x$ level without add-on control equipment. However, there is a risk that such a low level may not be achievable at all times.

**$SO_2$:** U. S. Sugar should not be required to meet a fuel oil sulfur limit predicated on regulations that will go into effect in 2006. This is premature, speculative, and not acceptable. First of all, the regulation could be revised and not go into effect in 2006, or be replaced by a less stringent standard. Secondly, the cost of such fuel is not known at this time, and since costs are considered in the BACT analysis, this alternative should be rejected. U. S. Sugar cannot control what other facilities propose as BACT, but to propose a technology that is not yet even available or known to be cost effective is not considered appropriate.

Please call or e-mail me if you have any questions concerning this additional information.

Sincerely,
GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer
Florida P. E. # 19011
SEAL

David T. Larocca

David T. Larocca
Project Engineer

DB/DTL/jej

Enclosure

cc: Don Griffin
Sarah Watson
Ron Blackburn, DEP
C. Holladay
G. Kettle, EPA
G. Bunyak, NPS

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**Table 1: ESP Performance Summary**

| PERFORMANCE PARAMETER | UNITS | RANGE of VALUES |
|---|---|---|
| DUST SOURCE | | Combustion |
| FUELS | | Bagasse / Fuel Oil |
| GAS VOLUME | ACFM | 425,425 |
| GAS TEMPERATURE | F | 255 – 335 |
| GAS MOISTURE | $\%_v$ | 24.3 - 25.0 |
| GAS PRESSURE | IWG | - 10 |
| INLET PM LOADING | #/MMBTU | 1.00 |
| EXIT PM LOADING | #/MMBTU | 0.03 |
| REMOVAL EFFICIENCY | % | 97.00 |
| PRESSURE DROP | IWG | 0.5 - 1.0 |
| OPACITY | % | 10 |
| POWER CONSUMPTION | KW | 231 – 303 |
| FIELD VOLTAGE | KV | 55 – 70 |
| CURENT | mA | 1,700 |
| NO. of FIELDS | | 3 – 4 |
| FIELD LENGTH | FT | 36.4 - 40.8 |
| COLLECTING PLATE HT | FT | 36 |
| TOTAL COLL. AREA | $FT^2$ | 91,665 - 144,550 |
| SP. COLL. AREA (SCA) | $FT^2$/kACFM | 215.5 - 339.8 |
| GAS VELOCITY | FT/SEC | 4.01 - 4.22 |
| TREATMENT TIME | SEC | 8.6 - 10.2 |
| ASPECT RATIO | | 1.01 - 1.36 |

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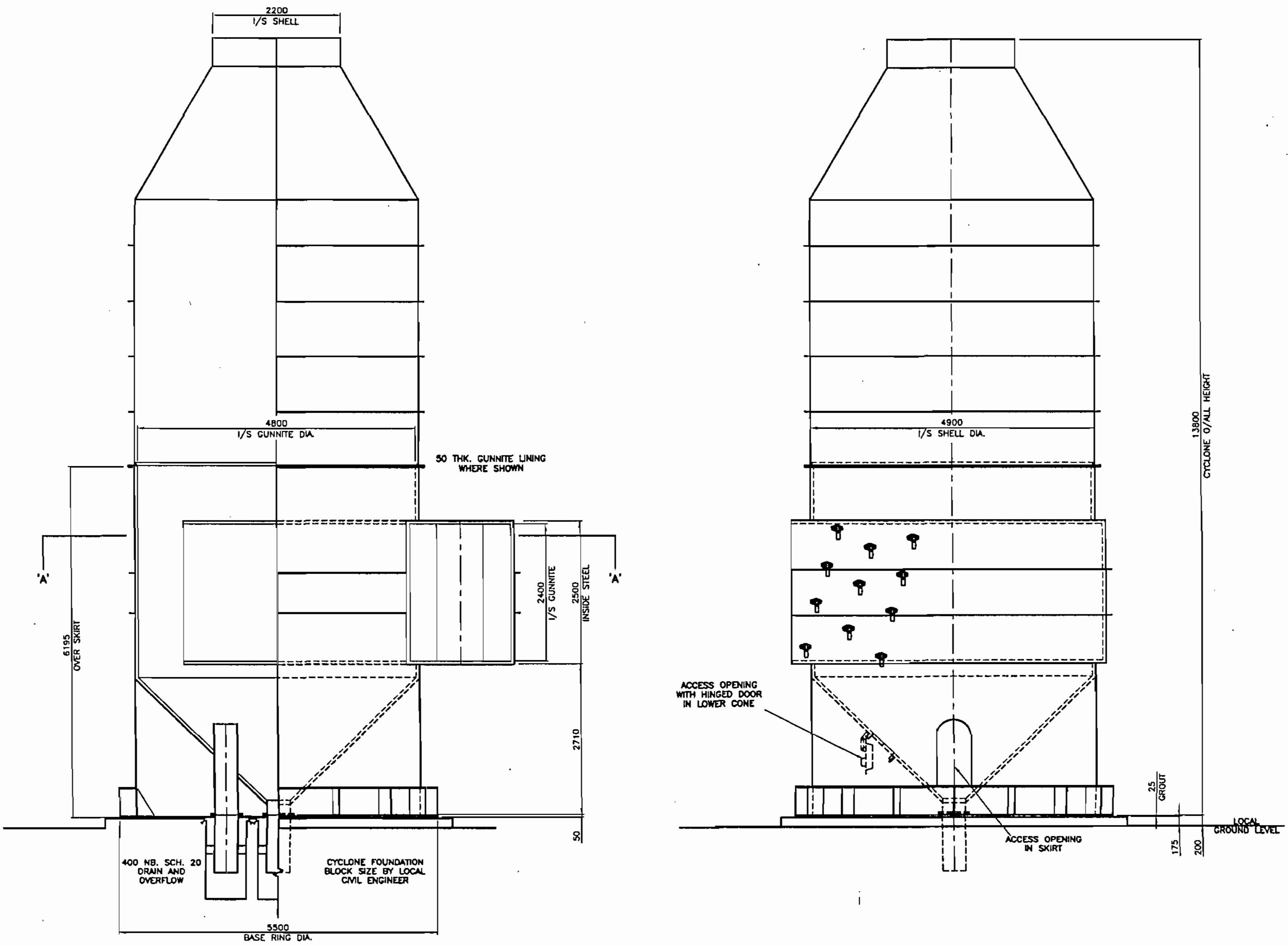
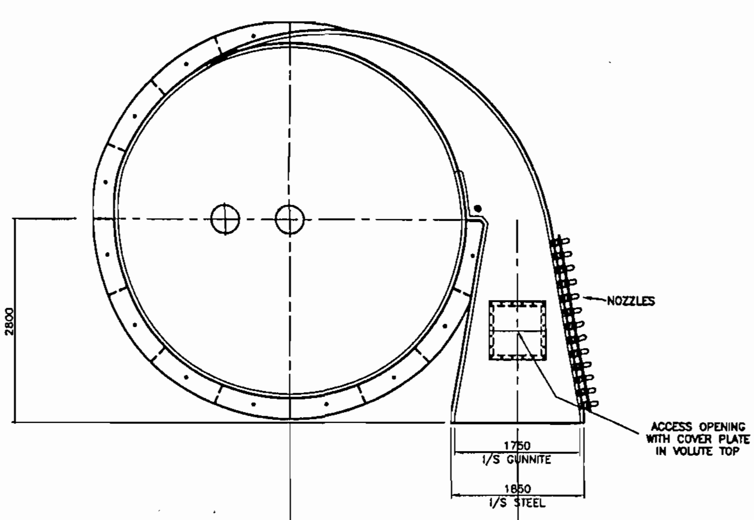
GENERAL NOTES
ALL DIMENSIONS IN MILLIMETRES.




SECTION A–A

0237619/4/4.1/L052103/04-999-026.dwg

magasiner technology

| | | | | |
|---|---|---|---|---|
| FIRST ISSUE | REV. | INITIAL | DATE | |
| | | DRAWN | CHECKED | APPRVD |

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THERMAL ENERGY SYSTEMS CC

THIRD ANGLE PROJECTION

U.S. SUGAR CORPORATION – CLEWISTON

PRELIMINARY ARRANGEMET
WET CYCLONE

Thermal Energy Systems

| | | | | | |
|---|---|---|---|---|---|
| DRAWN | J.R.W. | 8/5/03 | SCALE 1:40 | DRG. No. | 1/49–999–026 |
| CHECKD | JRW | | | | |
| APPRVD | BJM | | REV. | A | |

**ATTACHMENT A**

Table A-1. Cost Effectiveness of "Tail-End" SCR, U.S. Sugar Cogeneration Boiler 8

| Cost Items | | Cost Factors[a] | Cost ($) |
|---|---|---|---|
| DIRECT CAPITAL COSTS (DCC): | | | |
| | SCR Basic Process | Vendor quote[b] | 2,093,684 |
| | Ammonia Storage System | Vendor quote[c], 30,000 galllon storage tank + valves | 210,000 |
| | Auxilary Equipment (Reheat) | 20% of SCR equipment cost | 418,737 |
| | Emissions Monitoring | 15% of SCR equipment cost | 209,368 |
| | Foundation and Structure Support | 8% of SCR equipment cost | 167,495 |
| | Control Room and Enclosures | 4% of SCR equipment cost, engineering estimate | 83,747 |
| | Transition Ducts to and from SCR | 4% of SCR equipment cost, engineering estimate | 83,747 |
| | Wiring and Conduit | 2% of SCR equipment cost, engineering estimate | 41,874 |
| | Insulation | 2% of SCR equipment cost, engineering estimate | 41,874 |
| | Motor Control and Motor Starters | 4% SCR of equipment cost, engineering estimate | 83,747 |
| | SCR Bypass Duct | $127 per MMBtu/hr | 96,520 |
| | Induced Draft Fan | 5% of SCR equipment cost, engineering estimate | 104,684 |
| | Taxes | Florida sales tax, 6% | 125,621 |
| Total DCC: | | | 3,761,099 |
| INDIRECT CAPITAL COSTS (ICC): | | | |
| | General Facilities | 5% of DCC | 188,055 |
| | Engineering Fees | 10% of DCC | 376,110 |
| | Performance test | 1% of DCC | 37,611 |
| | Process Contingencies | 5% of DCC | 188,055 |
| Total ICC: | | | 789,831 |
| Project Contingencies | | 15% of DCC + ICC | 682,639 |
| TOTAL CAPITAL INVESTMENT (TCI): | | DCC + ICC + Project Contingencies | 5,233,569 |
| DIRECT OPERATING COSTS (DOC): | | | |
| (1) | Operating Labor | | |
| | Operator | 24 hours/week, $16/hr, 52 weeks/yr | $19,968 |
| | Supervisor | 15% of operator cost | 2,995 |
| (2) | Maintenance | Engineering estimate, 5% of catalyst replacement cost | 23,481 |
| (3) | SCR Energy Requirement | 0.3 % of output energy + 10 hp ammonia pump. @ $0.04/kW-hr | 218,029 |
| (5) | Ammonia Cost | $495 per ton NH3, 19% Aqueous (Tanner,2002). | 573,138 |
| (6) | Catalyst Replacement and disposal | 20,000 hours; 7%; FWF = 0.374 | 469,624 [d] |
| (7) | Reheat Energy Requirements | 133.8 MMBtu/hr; $0.8/Gallon fuel oil; 75% C.F | 5,169,237 [e] |
| Total DOC: | | | 6,476,474 |
| CAPITAL RECOVERY COSTS (CRC): | | CRF of 0.10979 times TCI (15 yrs @ 7%) | 574,594 |
| ANNUALIZED COSTS (AC): | | DOC + CRC | 7,051,067 |
| BASELINE $NO_x$ EMISSIONS (TPY) : | | 0.22 lb/MMBtu; 1030 MMBtu/hr; 75% capacity factor | 744.4 |
| MAXIMUM $NO_x$ EMISSIONS (TPY) : | | 80% removal | 148.9 |
| REDUCTION IN $NO_x$ EMISSONS (TPY): | | | 595.5 |
| COST EFFECTIVENESS: | | $ per ton of $NO_x$ Removed | 11,840 |

Footnotes:

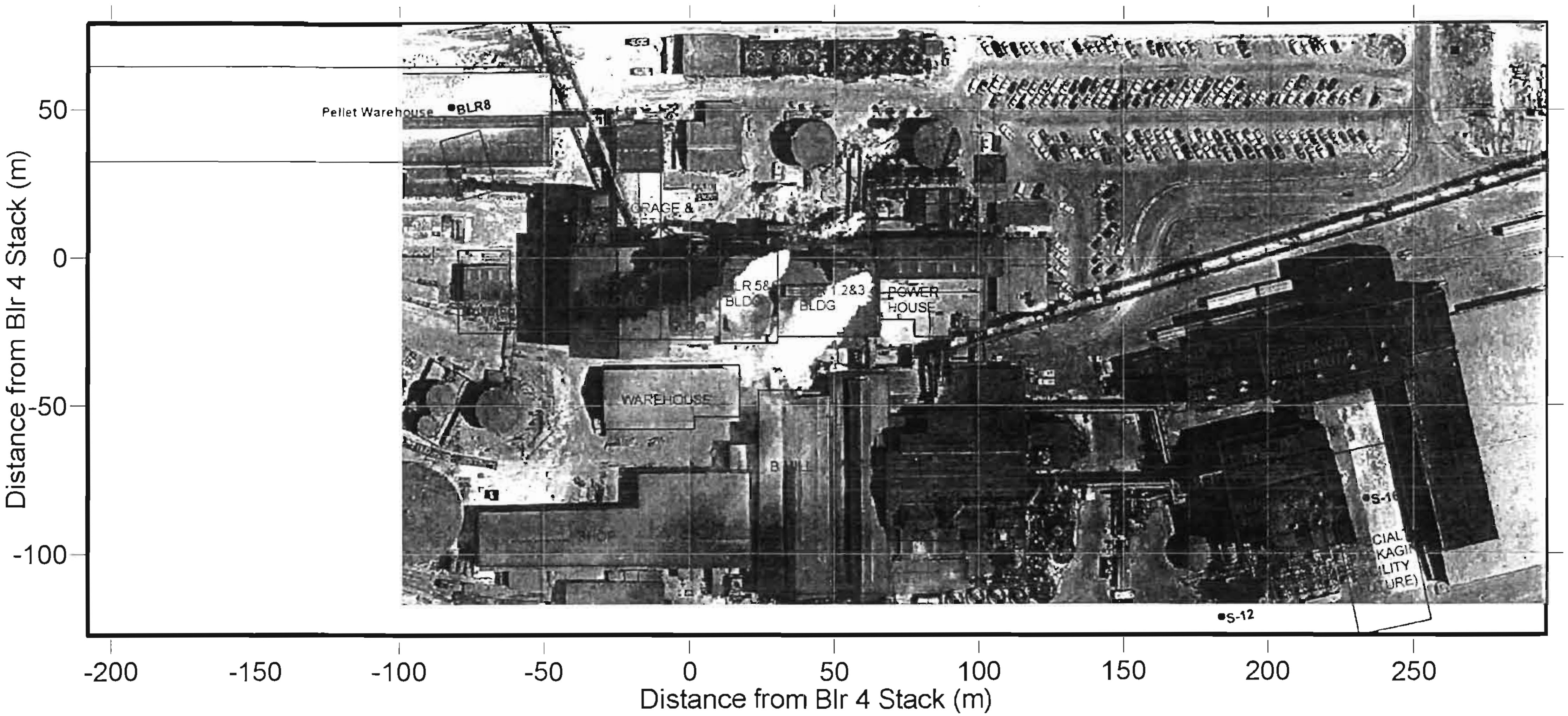
[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 4, Sixth edition.

[b] 2002 Hamon Research-Cottrell cost quote, 3 units = $4,250,000, includes SCR, ammonia flow control unit, and ammonia injection system. 1 cogeneration unit = $1,700,000. Original quote for 760 MMBtu/hr boiler. Cost scaled by a factor of 936/760 = 1.23

[c] Based on RM Technologies vendor quote for 30,000 gallon stainless steel horizontal tank, includes valves and transfer station.

[d] SCR initial catalyst cost estimated to be 60% (based on experience with Englehard SCR systems) of the initial capital cost, FWF = future worth factor OAQPS (2.52).

[e] Based on reheating 400,000 acfm from 330 deg. F to 700 deg. F.




Facility Plot Plan
U.S. Sugar – Boiler No. 8

Source: Golder, 2003.

Golder Associates

**ATTACHMENT B**

HAZEN

**Hazen Research, Inc.**
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

| | |
|---|---|
| Date | March 11 2003 |
| HRI Project | 009-555 |
| HRI Series No. | C2/03 |
| Date Rec'd. | 03/04/03 |
| Cust. P.O.# | |

Golder Associates, Inc.
Fawn Bergen
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653

Sample Identification:
USSC-B8 Ash

Elemental Analysis of Ash (%)

| | |
|---|---|
| SIO2 | 33.04 |
| AL203 | 2.13 |
| TIO2 | 0.04 |
| FE203 | 1.82 |
| CAO | 7.62 |
| MGO | 3.55 |
| NA2O | 0.26 |
| K2O | 15.00 |
| P205 | 6.22 |
| S03 | 9.32 |
| CL | |
| C02 | |
| Total | 79.00 |

Ash Fusion Temperatures (Deg F)

| | Oxidizing Atmosphere | Reducing Atmosphere |
|---|---|---|
| Initial | | |
| Softening | | |
| Hemispherical | | |
| Fluid | | |

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

Note: The ash was calcined @ 1110 deg F (600 C) prior to analysis.

HAZEN

**Hazen Research, Inc.**
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

| | |
|---|---|
| DATE | April 1, 2003 |
| PROJ. # | 009-455 |
| CTRL # | C2/03 |
| REC'D | 03/04/03 |

Golder Associates, Inc.
Fawn Bergen
6241 NW 23rd Street, Suite 500
Gainesville, FL 32653

Sample Number: C2/03-1
Sample Identification: USSC-B8 Ash

| | |
|---|---|
| Antimony, mg/kg | 38 |
| Arsenic, mg/kg | 10.4 |
| Cadmium, mg/kg | <1 |
| Chlorine, mg/kg | 75,800 |
| Chromium, mg/kg | 40 |
| Copper, mg/kg | 340 |
| Lead, mg/kg | 47 |
| Manganese, mg/kg | 470 |
| Mercury, mg/kg | <0.1 |
| Nickel, mg/kg | 11 |
| Selenium, mg/kg | 2 |
| Tin, mg/kg | <100 |
| Vanadium, mg/kg | 149 |
| Zinc, mg/kg | 1,690 |

By: Gerard H. Cunningham

Gerard H. Cunningham
Fuel Laboratory Manager

The sample was ashed at 600 degrees Celsius prior to analysis.

# ATTACHMENT C

# GENERAL, RESIDENTIAL, COMMERCIAL, INDUSTRIAL GROWTH ASSOCIATED WITH THE ADDITION OF BOILER NO. 8 AT U.S. SUGAR CORPORATION'S CLEWISTON MILL

Bagasse Fly Ash Compared to Coal Ash

| Constituent | ESP Ash From Boiler No. 7 | Coal Fly Ash | | | | |
|---|---|---|---|---|---|---|
| | | Class "F" | Class "C" | hvBb Utah | hvAb Penn. | hvC |
| Elemental analysis of ash (%) | | | | | | |
| Silica (SiO2) | 33.04 | 58.0 | 35.9 | 52.5 | 51.1 | 52.0 |
| Aluminum Oxide (Al2O3) | 2.13 | 29.1 | 18.9 | 18.9 | 30.7 | 17.5 |
| Iron Oxide (Fe2O3) | 1.82 | 3.6 | 6.1 | 1.1 | 10.0 | 15.5 |
| Titanium Oxide (TiO2) | 0.04 | 1.6 | 1.4 | 1.2 | 2.0 | 1.3 |
| Calcium Oxide (CaO) | 7.62 | 0.8 | 24.6 | 13.2 | 1.6 | 4.5 |
| Magnesium Oxide (MgO) | 3.55 | 0.8 | 5.4 | 1.3 | 0.9 | 1.1 |
| Sodium Oxide (Na2O) | 0.26 | 0.1 | 1.9 | 3.8 | 0.4 | 0.6 |
| Potassium Oxide (K2O) | 15.00 | 2.5 | 0.3 | 0.9 | 1.7 | 2.8 |
| Sulfur Trioxide (SO3) | 9.32 | 0.2 | 2.3 | 6.2 | 1.4 | 4.2 |
| Phosphorus Pentoxide (P2O5) | 6.22 | 0.1 | 1.1 | -- | -- | 0.1 |
| Barium Oxide (BaO) | -- | 0.1 | 0.7 | -- | -- | -- |
| Manganese Oxide (Mn2O3) | -- | 0.1 | <0.1 | -- | -- | -- |
| Strontium Oxide (SrO) | -- | 0.1 | 0.4 | -- | -- | -- |
| Trace metals (ppm): | | | | | | |
| Antimony | 38 | | | | | |
| Arsenic | 10.4 | | | | | |
| Cadmium | <1 | | | | | |
| Chlorine | 75,800 | | | | | |
| Chromium | 40 | | | | | |
| Copper | 340 | | | | | |
| Lead | 47 | | | | | |
| Manganese | 470 | | | | | |
| Mercury | <0.1 | | | | | |
| Nickel | 11 | | | | | |
| Selenium | 2 | | | | | |
| Tin | <100 | | | | | |
| Vanadium | 149 | | | | | |
| Zinc | 1,690 | | | | | |

## TABLE OF CONTENTS

# 1.0 INTRODUCTION

Florida Administrative Code (F.A.C.), 62-212.400(3)(h)(5), states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the construction and operation of Boiler No. 8. This information is consistent with the EPA Guidance related to this requirement in the Draft New Source Review Workshop Manual (EPA, 1990).

In general, there has been minimal growth in the area since 1977. The site is located in northeast Hendry County, to the south of Lake Okeechobee. Hendry County is the 8$^{th}$ largest county in Florida, comprising of 1,163 squares miles.

As stated in the PSD permit application, Boiler No. 8 is being constructed to meet current and projected demands for the Clewiston sugar mill. Additional growth as a direct result of the additional demand provided by the project is expected to be minimal. Construction of Boiler No. 8 will occur over approximately a 2-year period, requiring an average of approximately 25 workers during that time. It is anticipated that many of these construction personnel will commute to the site.

The addition of Boiler No. 8, coupled with the removal of Boiler No. 3, will result in no increase in operational workers at the site. The increase in production rate of the sugar refinery will not require any additional workers. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to operate Boiler No. 8 represents a small fraction of the population already present in the immediate area. Therefore, while there may be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated industrial and commercial growth, given the location at the existing Clewiston Mill. The existing commercial and industrial infrastructures are adequate to provide any support services that the project might require and would not increase with the operation of the project.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Hendry County. As such, the information presents information available from a variety of sources (e.g., Florida Statistical Abstract, FDEP, etc.) that characterizes Hendry County as a whole.

# 2.0 RESIDENTIAL GROWTH

## 2.1 POPULATION AND HOUSEHOLD TRENDS

As an indicator of residential growth, the trend in the population and number of household units in Hendry County since 1977 are shown in Figure C-1. The county experienced a 114 percent increase in population for the years 1977 through 2000. During this period, there was an increase in population of about 19,300. Similarly, the number of households in the county increased by about 4,700 or 77 percent since 1977.

## 2.2 GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT

Because of the limited number of workers needed to operate the project, residential growth due to the project is expected to be minimal.

# 3.0 COMMERCIAL GROWTH

## 3.1 RETAIL TRADE AND WHOLESALE TRADE

As an indicator of commercial growth in Hendry County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure C-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches and offices that sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977, retail trade has increased by 29 establishments and 1,013 employees or 28 and 128 percent, respectively. For the same period, wholesale trade has increased by 25 establishments and 179 employees, or 179 and 232 percent, respectively.

## 3.2 LABOR FORCE

The trend in the labor force in Hendry County since 1977 is shown in Figure C-3. The greatest number of persons employed in Hendry County has been in the agriculture, services and government sectors. Between 1977 and 1999, approximately 6,265 persons were added to the available work force, for an increase of 87 percent.

## 3.3 TOURISM

Another indicator of commercial growth in Hendry County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure C-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1978 and 2000, there was no change in the number of hotels and motels in the county; however there was a significant increase of 49 percent in the number of units at those facilities.

### 3.4 TRANSPORTATION

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Hendry County is presented in Figure C-5.

Much of the county's land is wetlands. A large part of the Big Cypress Seminole Indian Reservation is in the southern portion of the county. The county's main artery is State Road 80, which runs east-west through the northern section of the county. The only other major highway in the county is U.S. Highways 27. State and county highways in the county include S.R. 29, and County Roads 832, 833, 832, 846, and 858.

Between 1977 and 2001, there was an increase of about 280,000 VMT, or 86 percent, in the amount of travel by motor vehicles on major roadways in the county.

### 3.5 GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the project. The workforce needed to operate the proposed project represents a small fraction of the labor force present in the immediate and surrounding areas.

# 4.0 INDUSTRIAL GROWTH

## 4.1 UTILITIES

There are no existing power plants in Hendry County.

## 4.2 MANUFACTURING AND AGRICULTURAL INDUSTRIES

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Hendry County since 1977 is shown in Figure C-6. As shown, the manufacturing industry experienced a moderate increase of 25 percent from 1977 through 1997.

As another indicator of industrial growth, the trend in the number of employees in the agricultural industry, including sugar, in Hendry County since 1977 is also shown in Figure C-6. As shown, the agricultural industry experienced an increase in employment of 91 percent from 1977 through 2000.

## 4.3 GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT

Since the baseline date of August 7, 1977, there have been only a few major facilities built within a 35-km-radius of the plant site. The nearest such source is the Southern Gardens Citrus Processing Corporation. There are a limited number of facilities located throughout the 35-km radius area surrounding the U.S. Sugar facility. Based on the plot of nearby emission sources, Figure C-7, there has not been a concentration of industrial and commercial growth in the vicinity of the U.S. Sugar Clewiston Mill.

## 5.0 AIR QUALITY DISCUSSION

### 5.1 AIR EMISSIONS AND SPATIAL DISTRIBUTION OF MAJOR FACILITIES

The spatial distribution of major air pollutant facilities in Hendry County is shown in Figure C-7. Based on actual emissions reported for 1999 (latest year of available data) by EPA on its AIRSdata website, total emissions from stationary sources in the county are as follows:

- Sulfur dioxide ($SO_2$): 1,591 TPY
- Particulate matter ($PM_{10}$): 538 TPY
- Nitrogen oxides ($NO_x$): 1003 TPY
- Carbon monoxide (CO): 8,167 TPY
- Volatile organic compounds (VOC): 549 TPY

### 5.2 AIR EMISSIONS FROM MOBILE SOURCES

The trends in the air emissions of CO, VOC, and $NO_x$ from mobile sources in Hendry County are presented in Figure C-8. Between 1977 and 2002, there were significant decreases in these emissions. The decrease in CO, VOC, $NO_x$ emissions were about 81, 7, and 4 tons per day, respectively, which represent decreases of 80, 80, and 56 percent, respectively, from 1977 emissions.

### 5.3 AIR MONITORING DATA

Since 1977, Hendry County has been classified as attainment for all criteria pollutants. Because of the minimal industrial, commercial, and residential development in Hendry County over the last 25 years, PM air quality monitoring data have not been collected in the county by the FDEP, except for total suspended particulates (TSP) for years 1977 through 1988. Air quality monitoring data have been collected in the adjacent county of Palm Beach due to the industrial, commercial, and residential activities that have occurred in the eastern portion of the county. For this evaluation, the air quality monitoring data collected at the monitoring station nearest to Clewiston were used to assess air quality trends since 1977.

For $SO_2$ concentrations, air quality monitoring data collected over the years from Riviera Beach, Belle Glade, and South Bay were used in the evaluation. For $NO_2$ concentrations, air quality monitoring data from West Palm Beach and Palm Beach were used. For $PM_{10}$ concentrations, air quality monitoring data from Clewiston and Belle Glade were used in the evaluation. For ozone concentrations, air quality monitoring data from West Palm Beach, Palm Beach, Delray Beach, and

Royal Palm Beach were used. Data collected from these stations are considered to be generally representative of air quality in Hendry County. Because these monitoring stations are generally located in more industrialized areas than the Clewiston area, the reported concentration are likely to be somewhat higher than that experienced at the Clewiston site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable ambient air quality standards. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources as well as meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than those monitored concentrations.

In addition, since 1988, PM in the form of $PM_{10}$ has been collected at the air monitoring stations due to the promulgation of the $PM_{10}$ AAQS. Prior to 1989, the AAQS for PM was in the form of TSP concentrations, and this form was measured at the stations.

### 5.3.1 $SO_2$ CONCENTRATIONS

The trends in the annual, 24-hour, and 3-hour average $SO_2$ concentrations measured near the Clewiston site since 1977 are presented in Figures 8-9 through 8-11, respectively. $SO_2$ concentrations have been measured at three stations for various time periods throughout these years.

As shown in these figures, concentrations have been and continue to be well below the AAQS.

### 5.3.2 $PM_{10}$/TSP CONCENTRATIONS

The trends in the annual and 24-hour average $PM_{10}$ and TSP concentrations since 1977 are presented in Figures A-12 and A-13, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to $PM_{10}$.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS. Since 1988 when $PM_{10}$ concentrations have been measured, the $PM_{10}$ concentrations have been and continue to be below the AAQS.

### 5.3.3 $NO_2$ CONCENTRATIONS

The trends in the annual average $NO_2$ concentrations measured at the nearest monitors to Clewiston are presented in Figure C-14. As shown in this figure, measured $NO_2$ concentrations have been well below the AAQS.

### 5.3.4 OZONE CONCENTRATIONS

The trends in the 1-hour average ozone concentrations since 1977 are presented in Figure C-15. As shown in this figures, even in the more urbanized areas of Palm Beach County, the measured ozone concentrations have been well below the AAQS.

## 5.4 AIR QUALITY ASSOCIATED WITH THE OPERATION OF THE PROJECT

The air quality data measured in the region of the Clewiston Mill indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for Boiler No. 8 are predicted to be below the significant impact levels, the air quality concentrations in the region are expected to remain below and comply with the AAQS when Boiler No. 8 becomes operational.

# Figure C-1. Population and Household Unit Trends in Hendry County

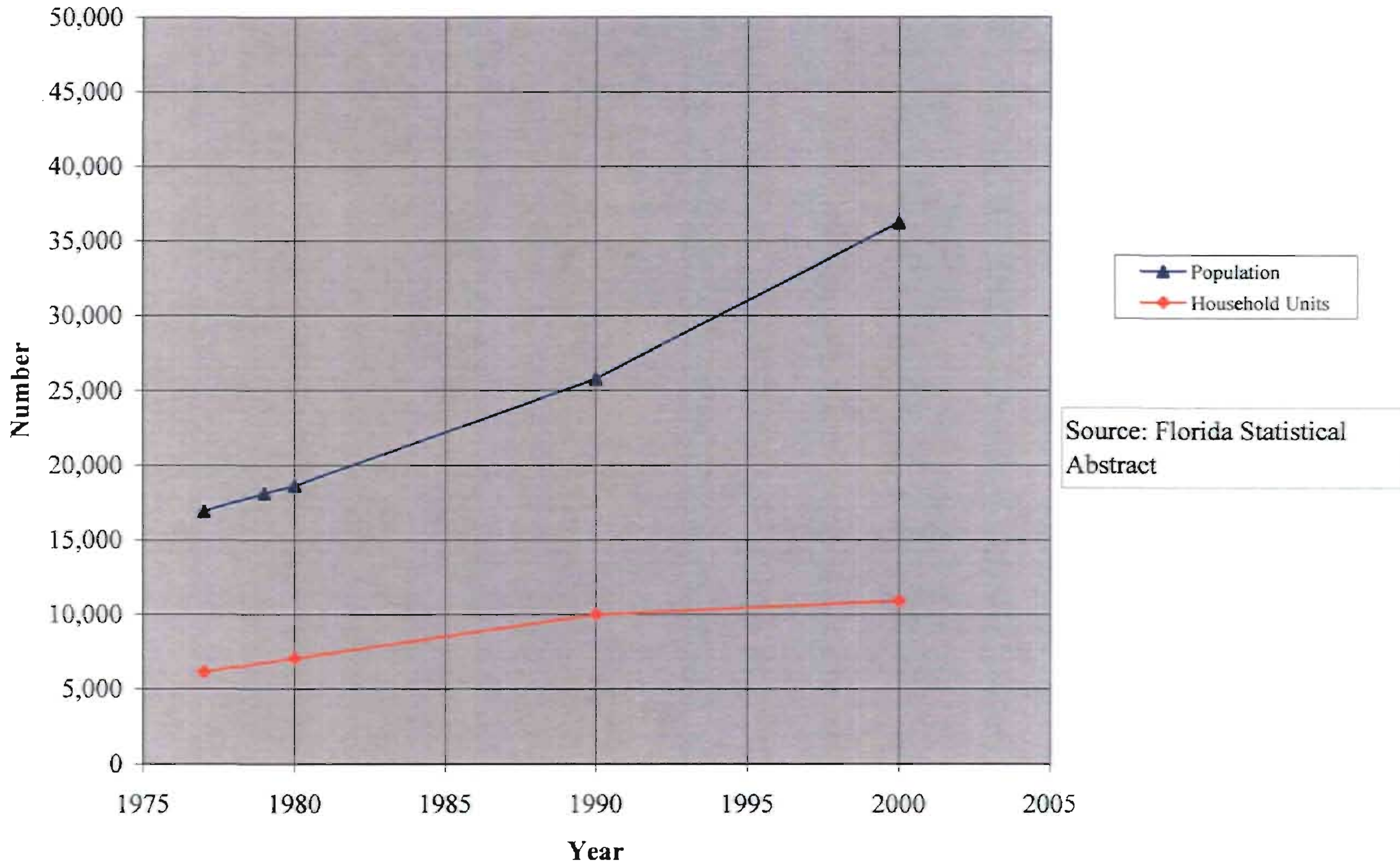
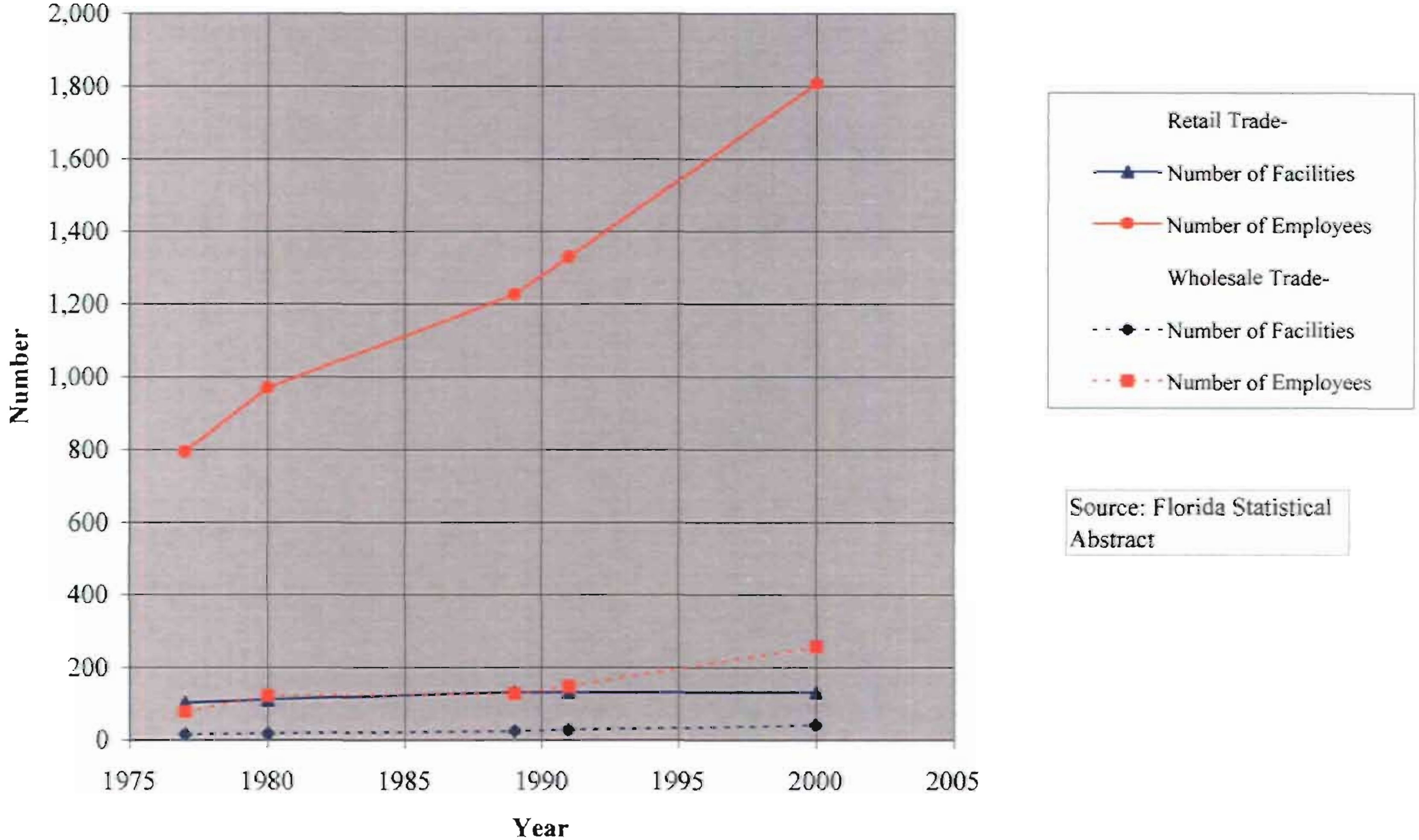
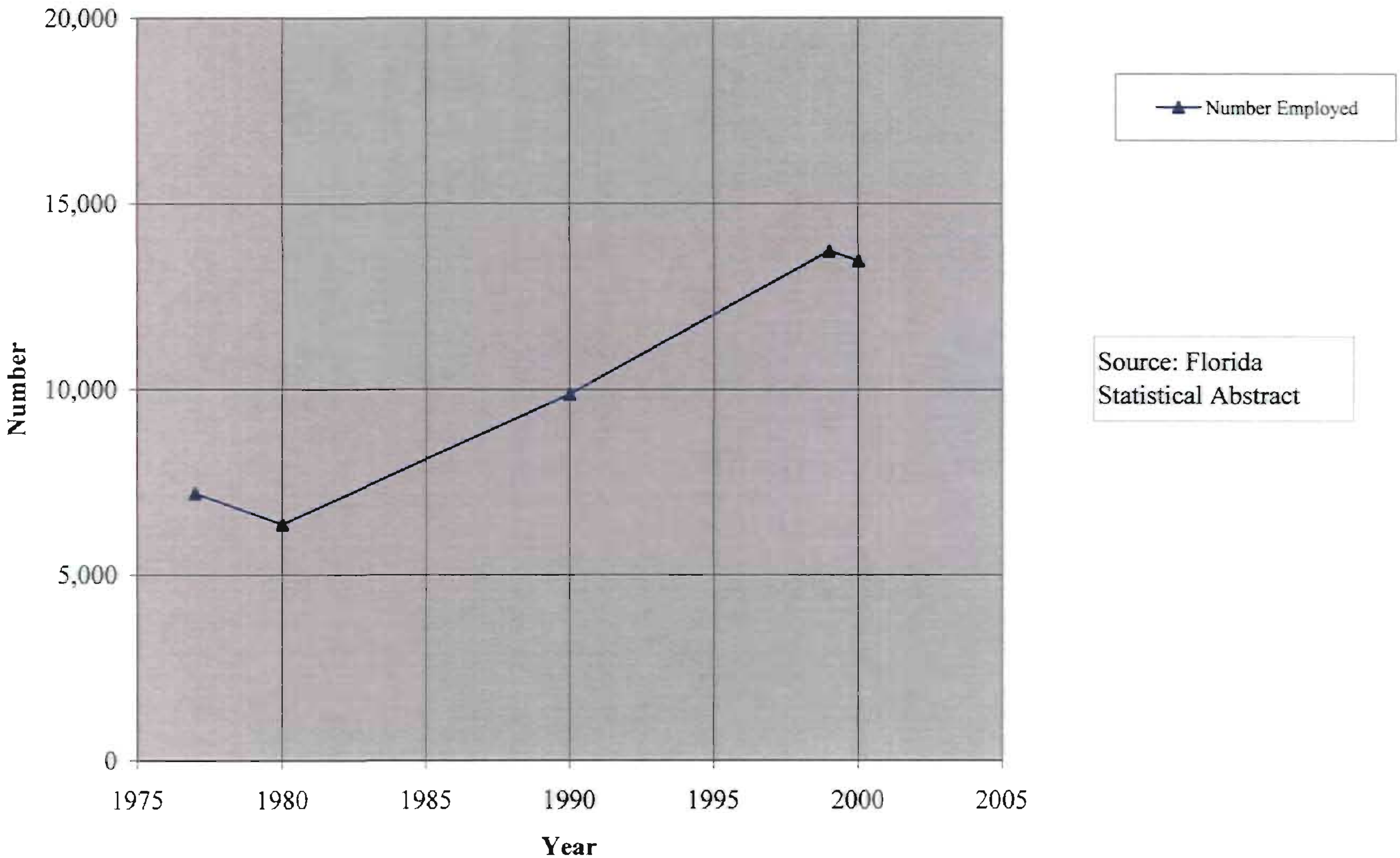


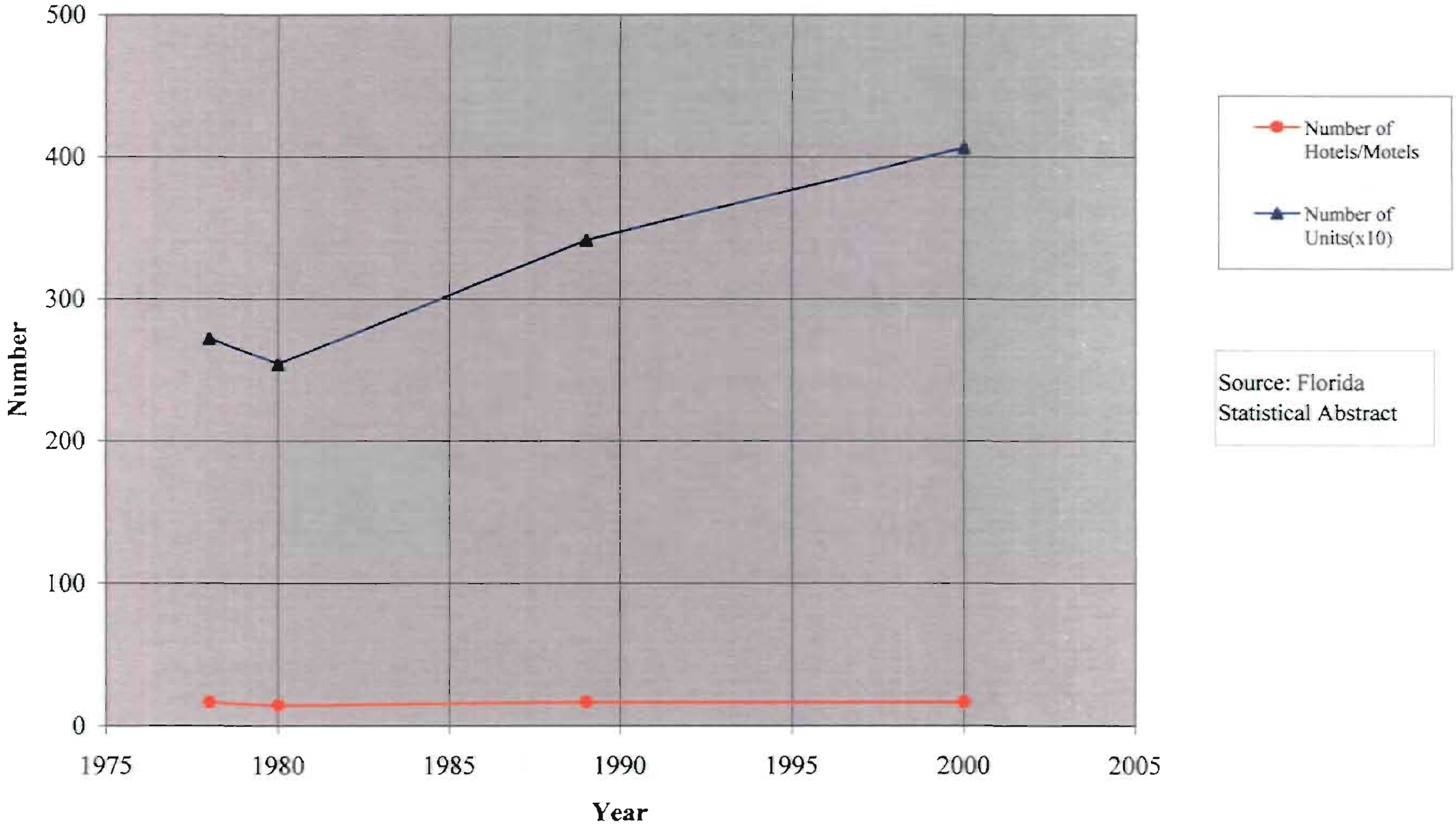
**Figure C-2. Retail and Wholesale Trade Trends in Hendry County**



# Figure C-3. Labor Force Trend in Hendry County



# Figure C-4. Hotel & Motel Trends in Hendry County



# Figure C-5. Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Hendry County

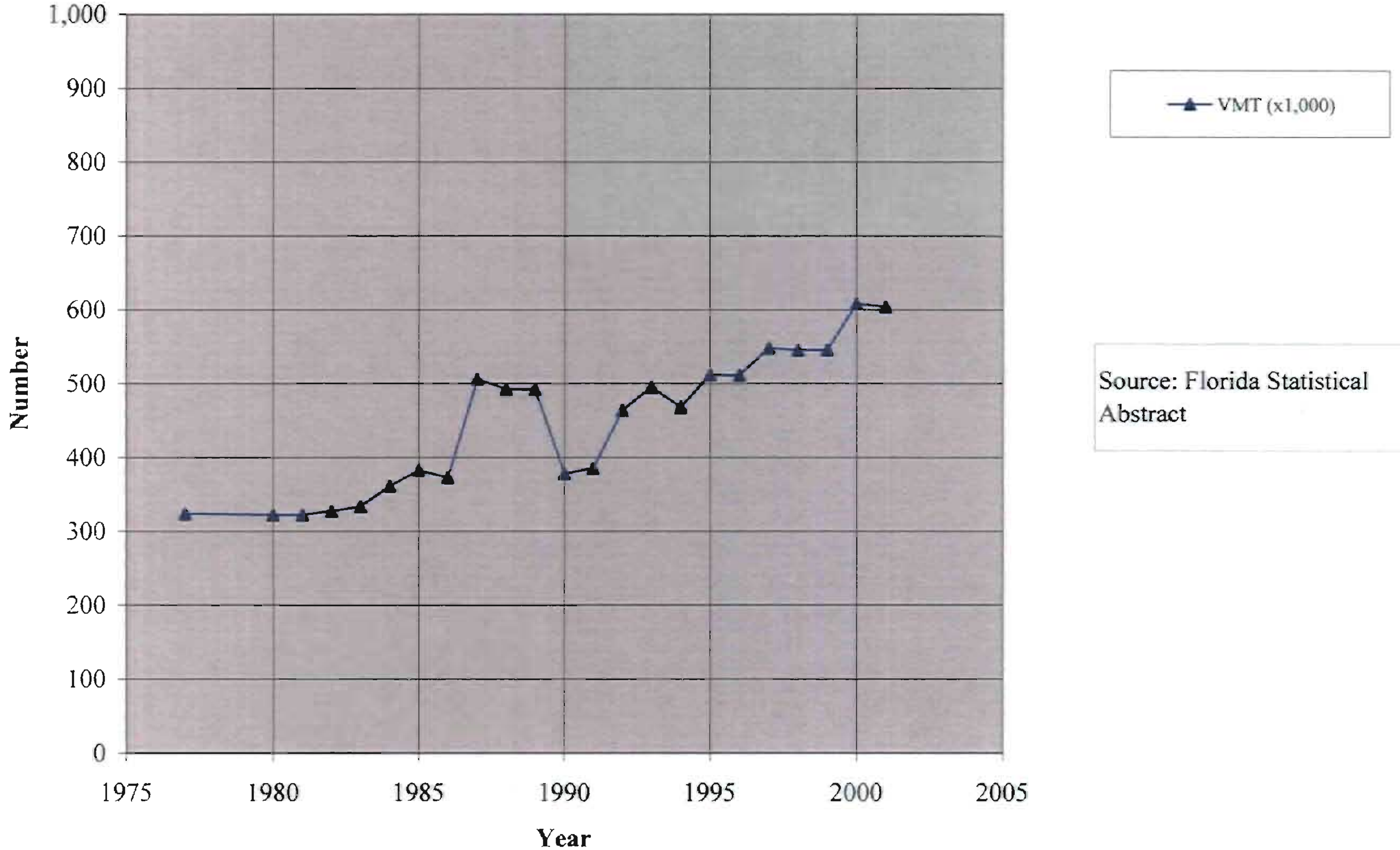
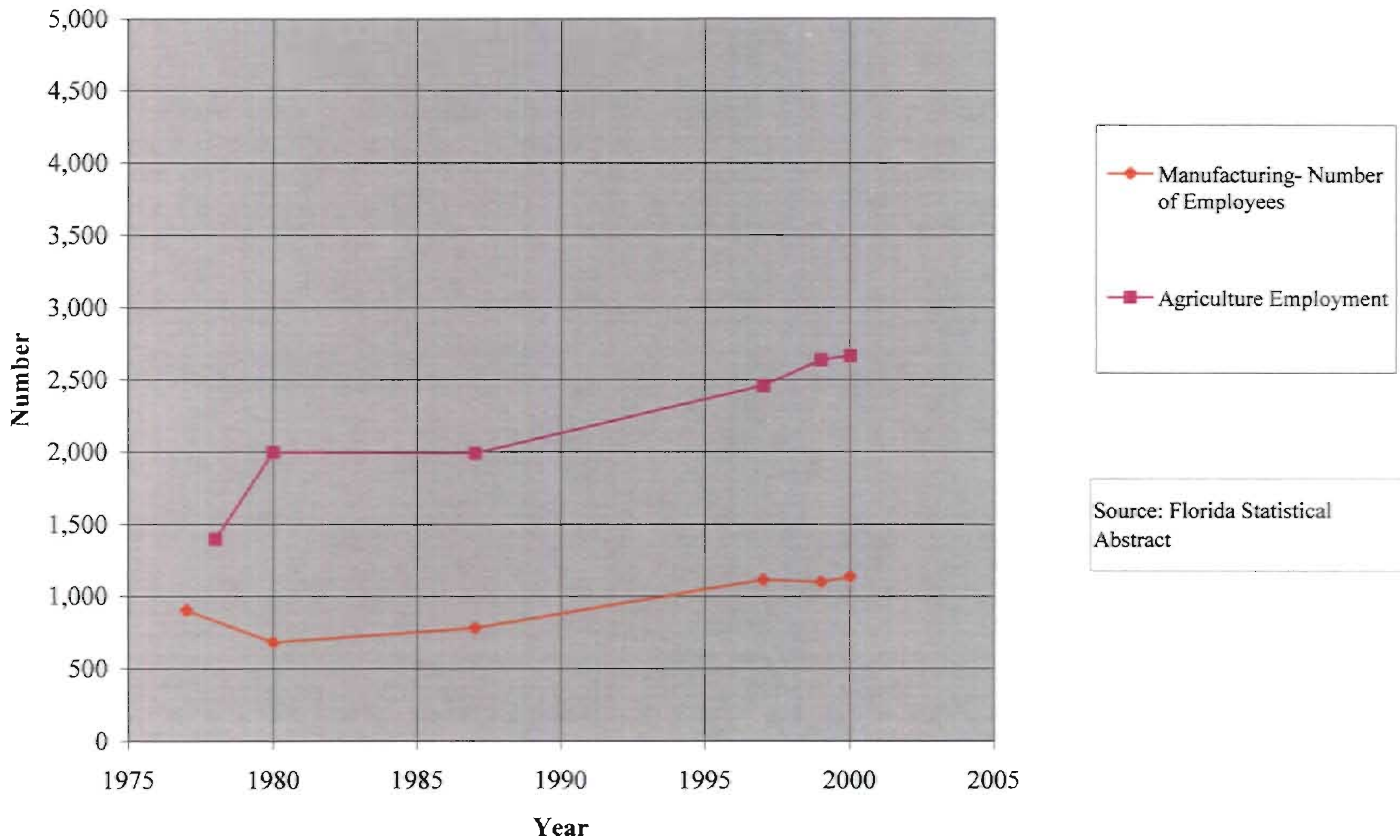


**Figure C-6. Manufacturing and Agriculture Trends in Hendry County**



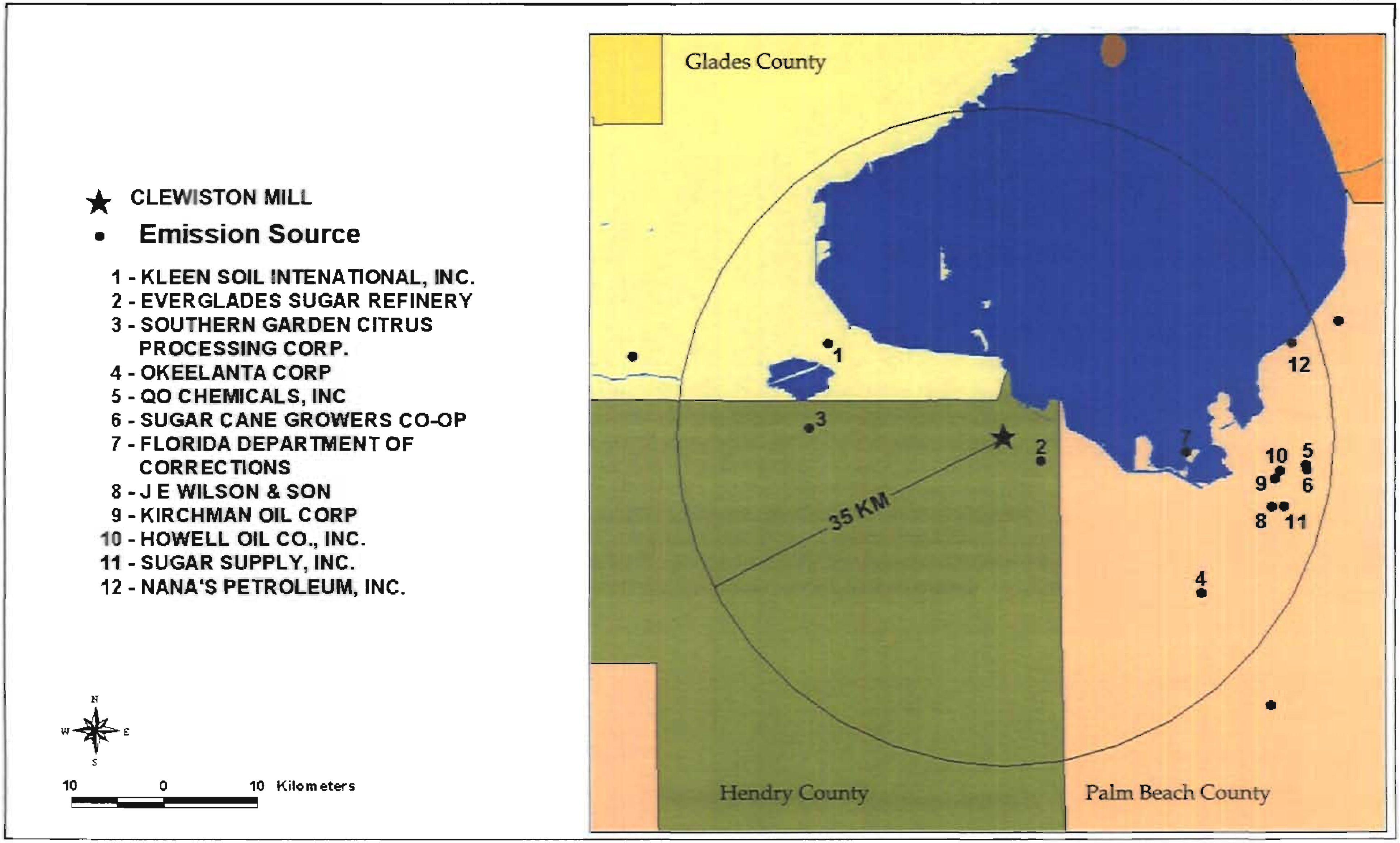



Figure C-7
Nearby Emission Sources

Golder Associates

# Figure C-8. Mobile Source Emissions (Tons per Day) of CO, VOC, and NOx in Hendry County

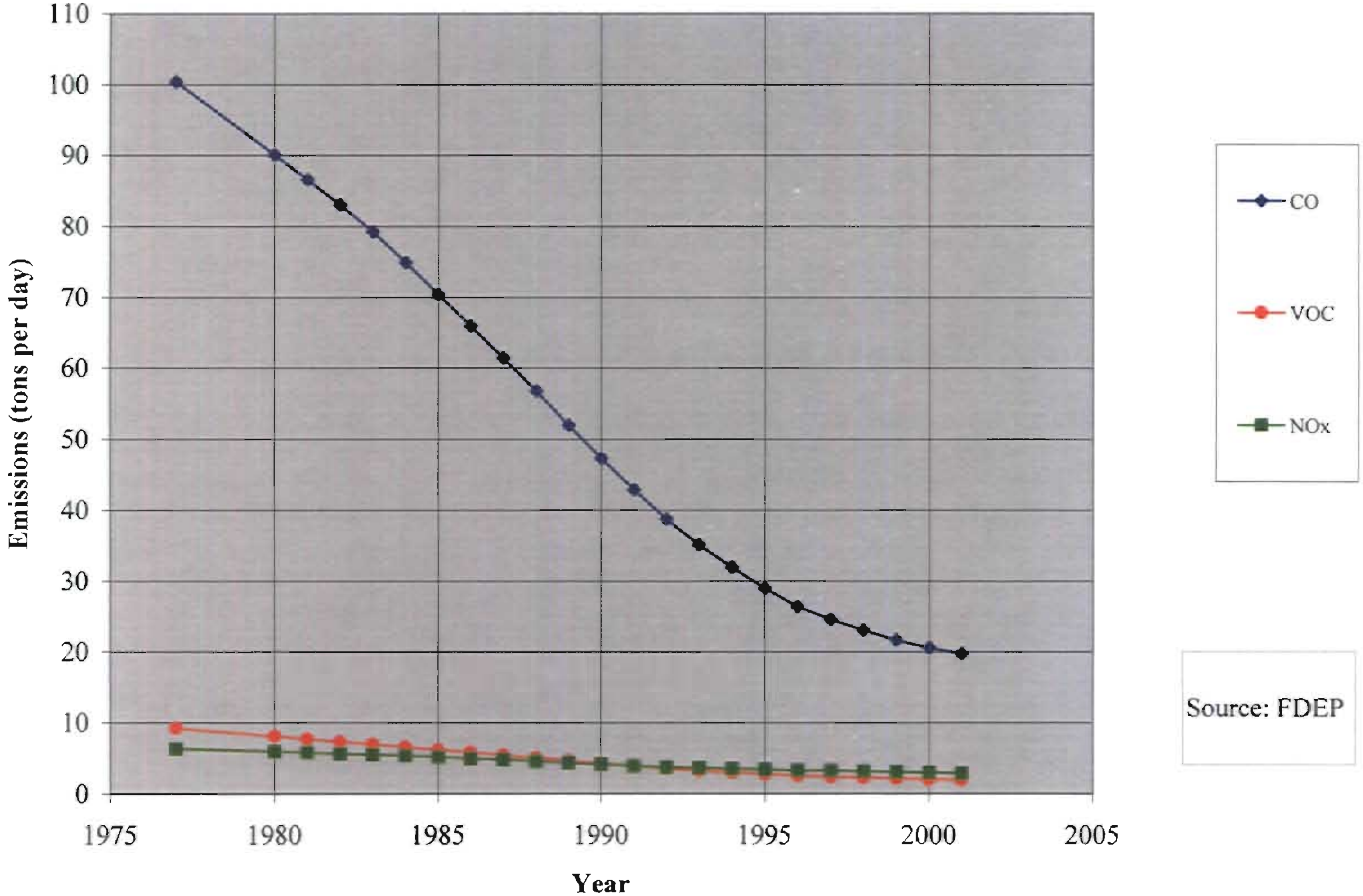


**Figure C-9. Measured Annual Average Sulfur Dioxide Concentrations from 1977 to 2002- Palm Beach County**

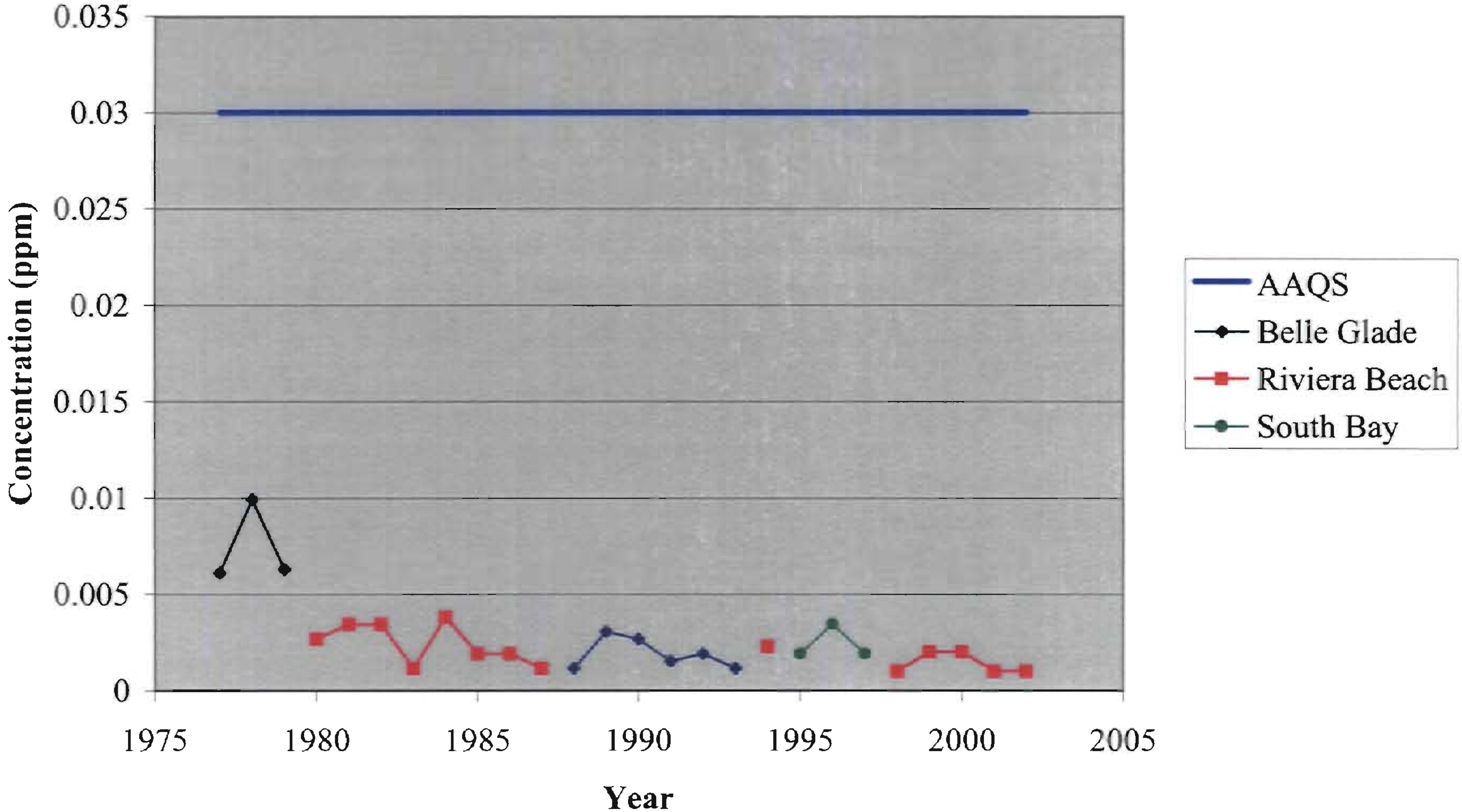


**Figure C-10. Measured 24-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) from 1977 to 2002- Palm Beach County**

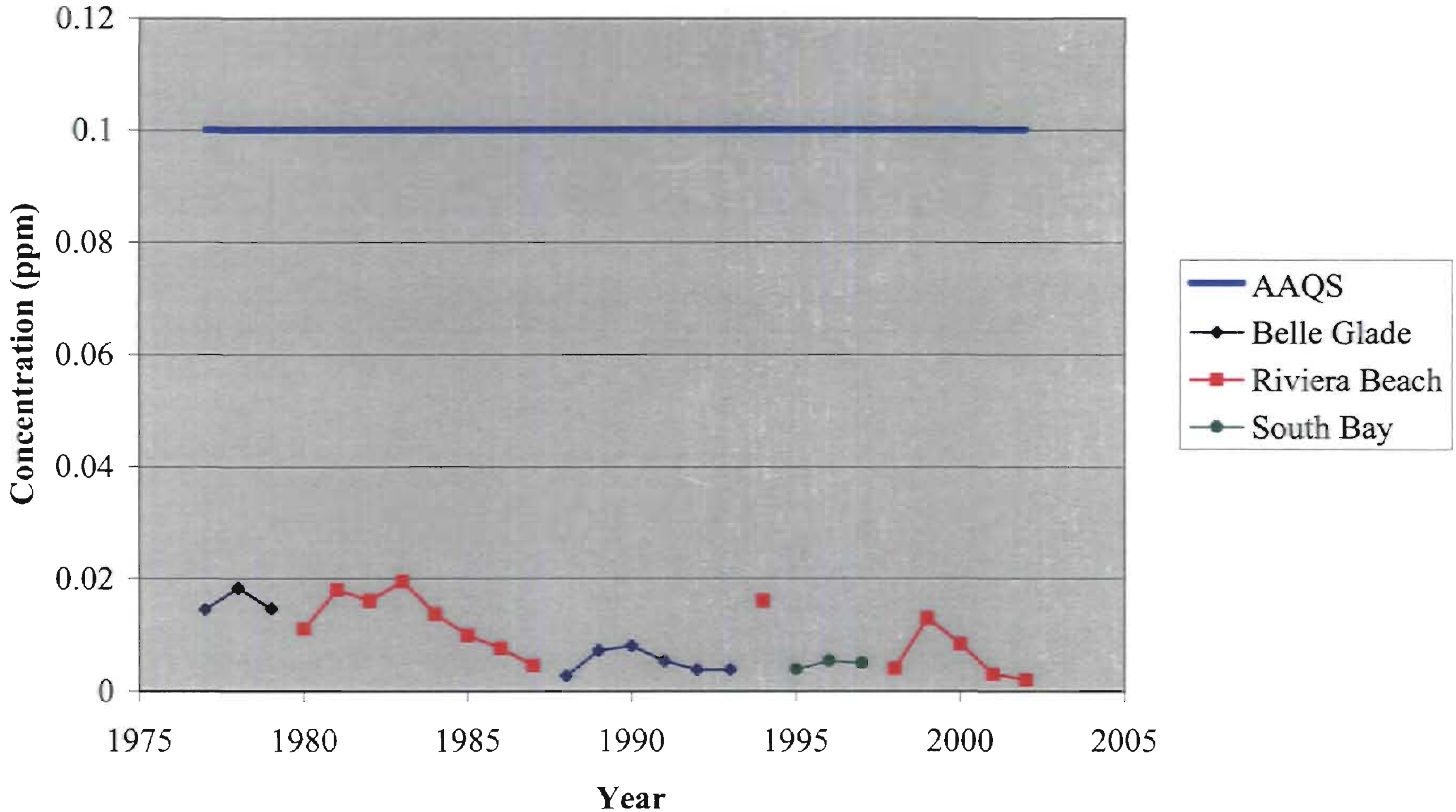


**Figure C-11. Measured 3-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) from 1977 to 2002- Palm Beach County**

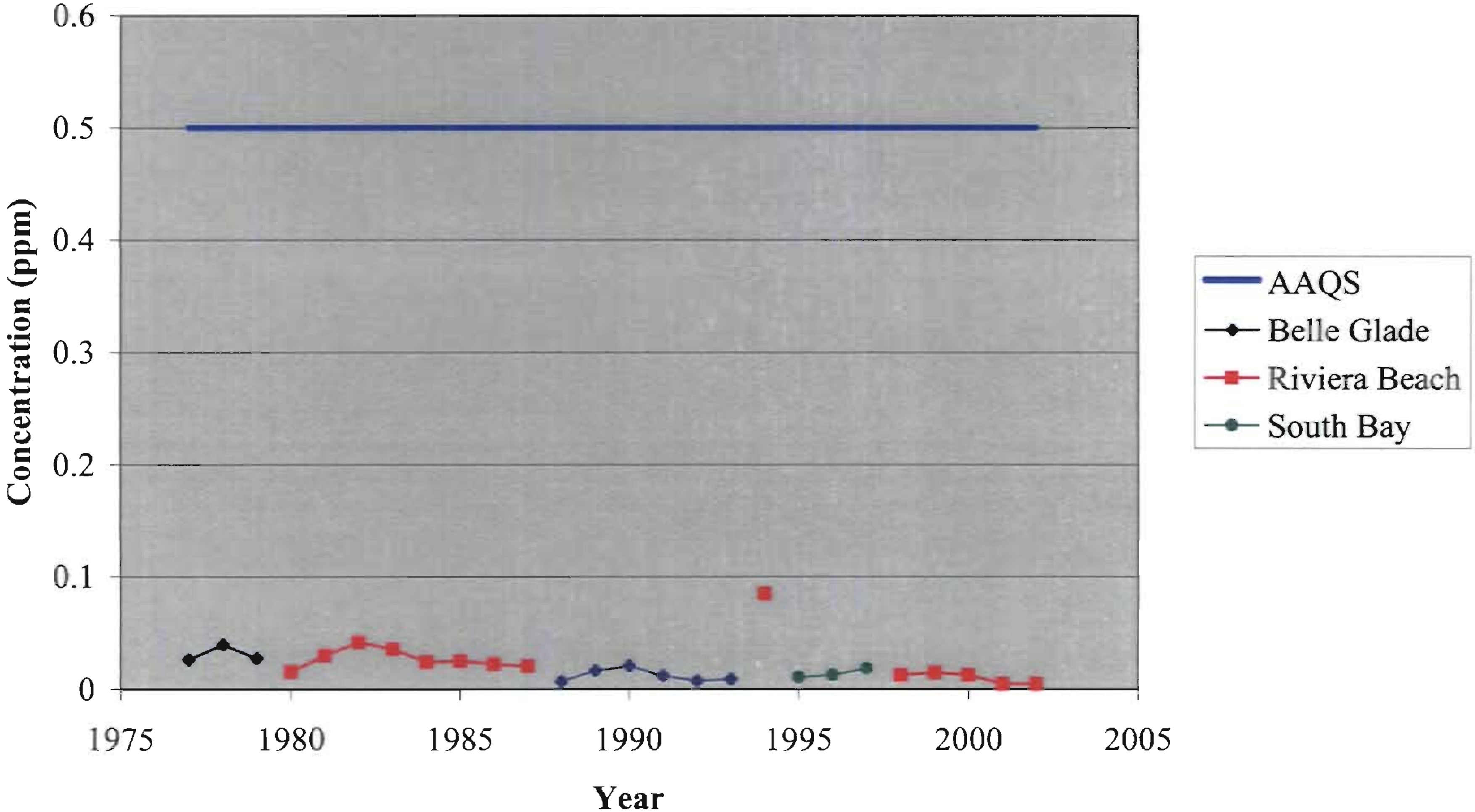


**Figure C-12. Measured Annual Average PM10 Concentrations and TSP Concentrations in Hendry and Palm Beach County**

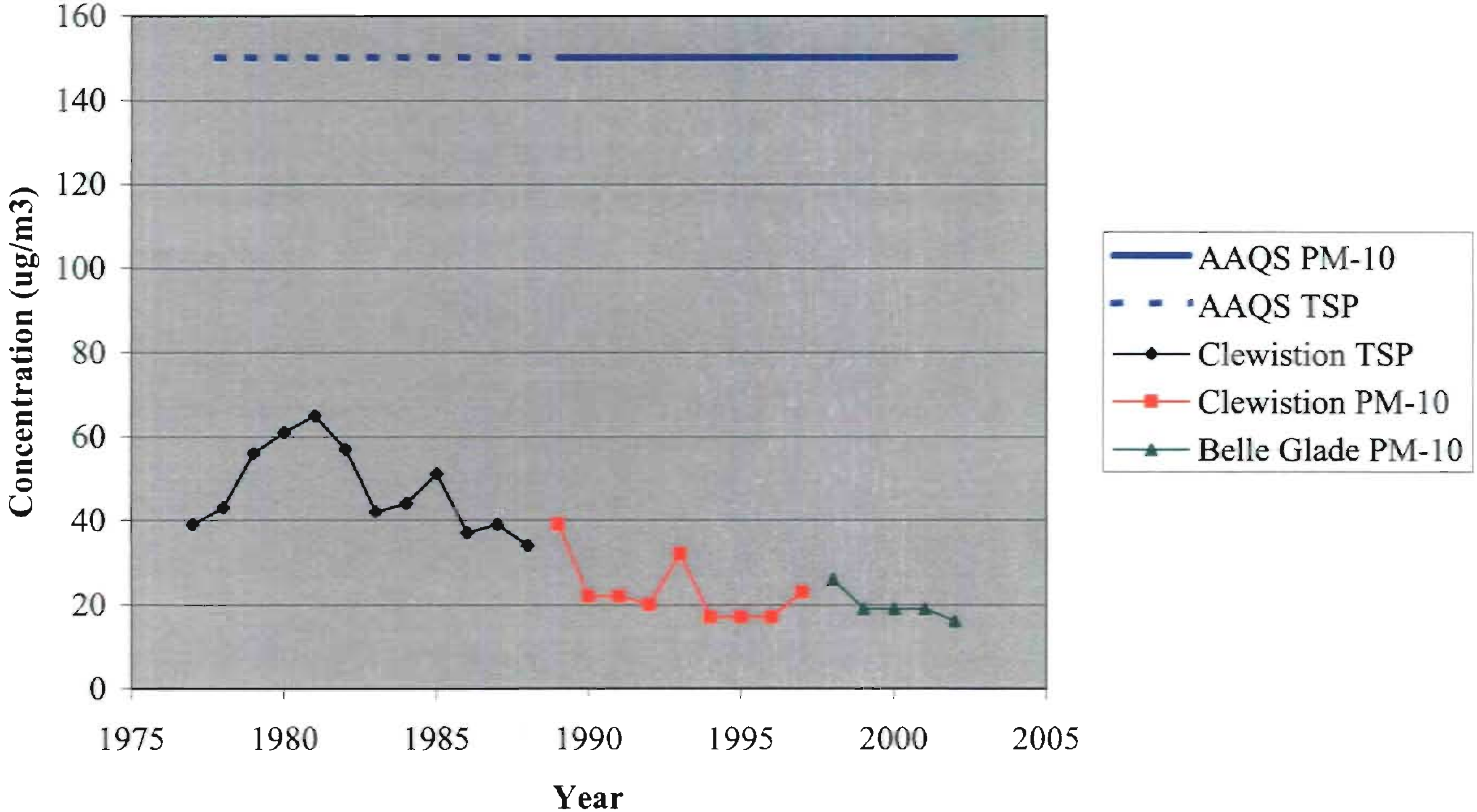


**Figure C-13. Measured 24-Hour Average PM10 Concentrations and TSP Concentrations (2nd Highest Values) in Hendry and Palm Beach County**

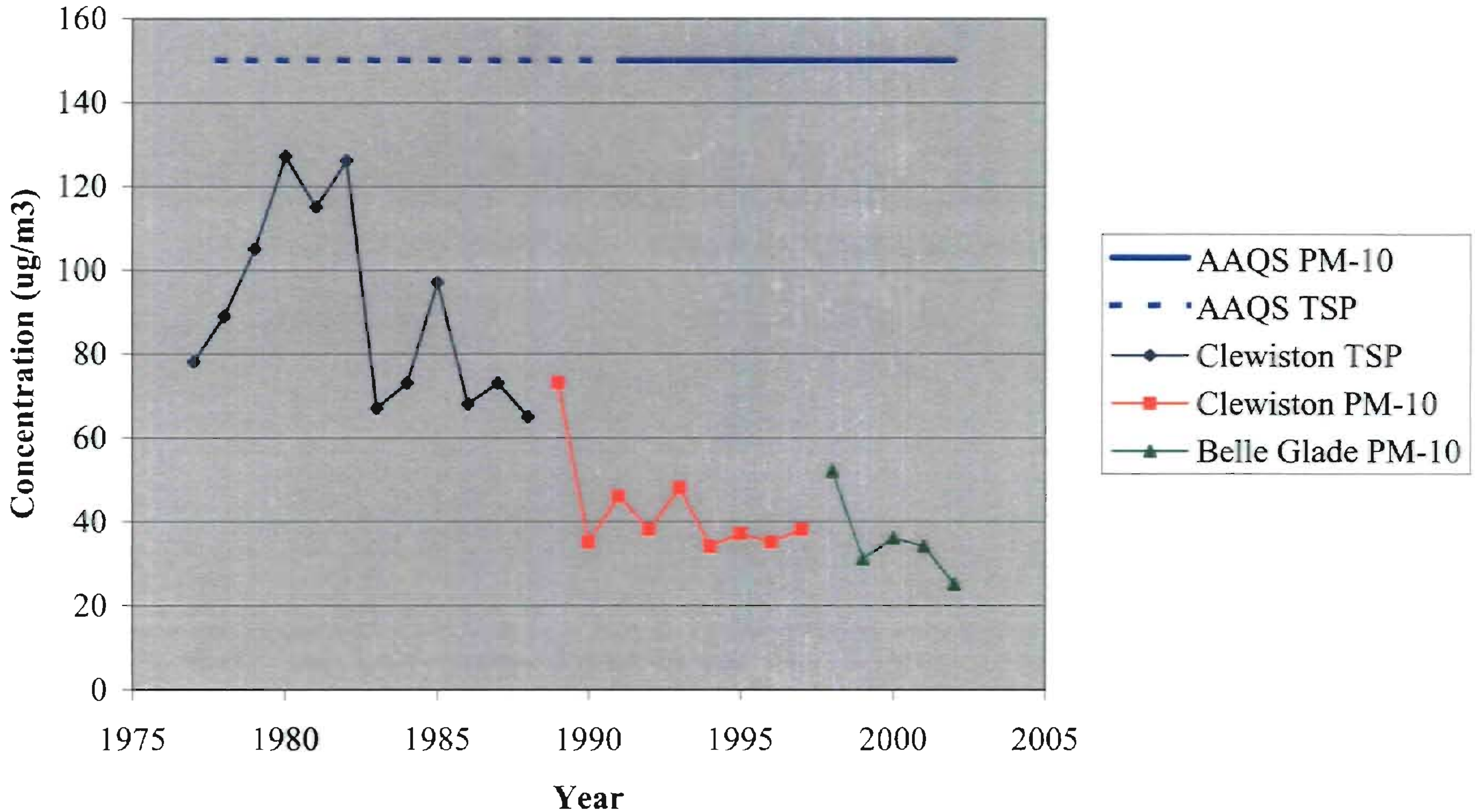


**Figure C-14. Measured Annual Average Nitrogen Dioxide Concentrations in Palm Beach County**

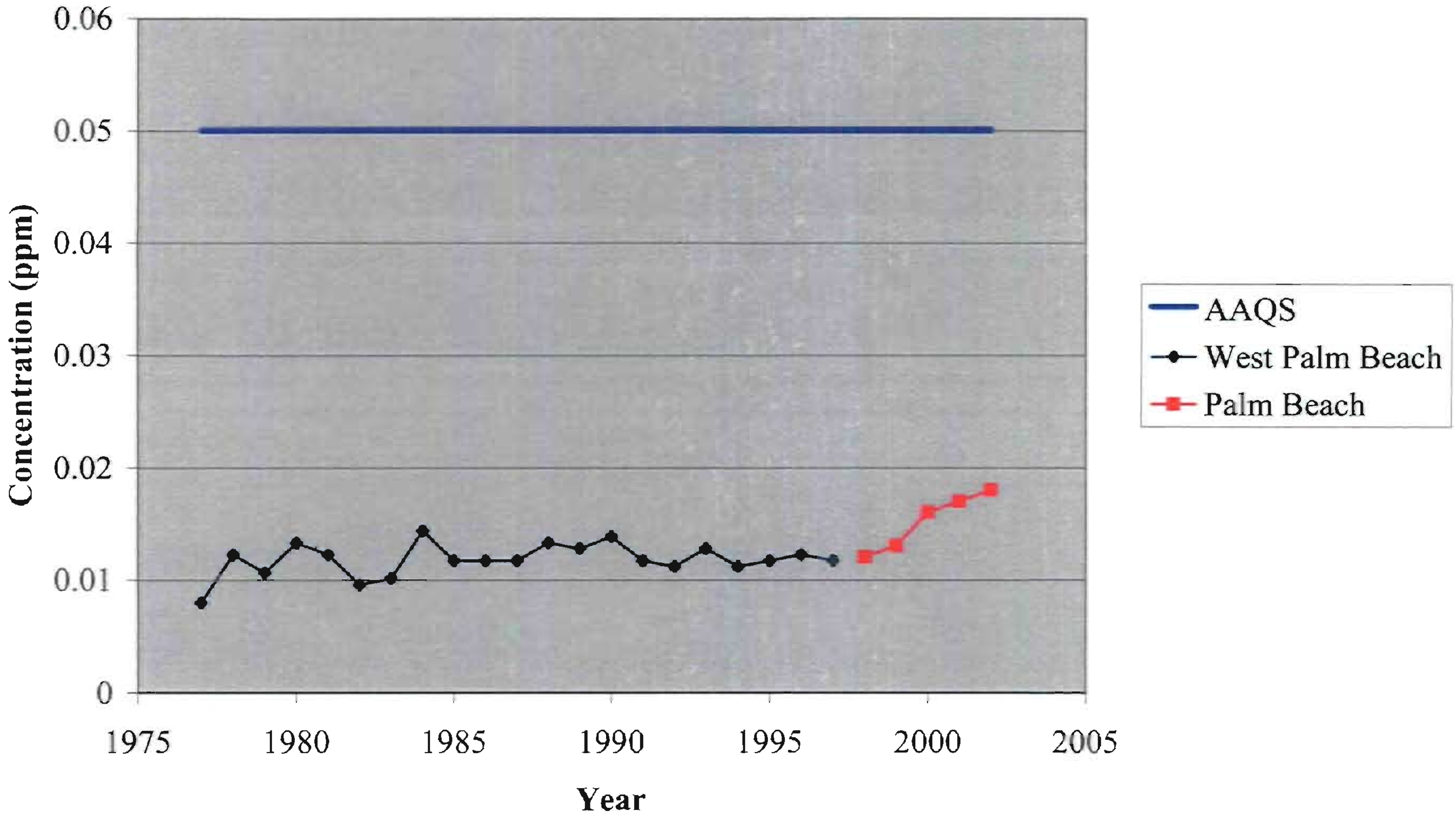


**Figure C-15. Measured 1-Hour Average Ozone Concentrations (2nd Highest Values) in Palm Beach County**

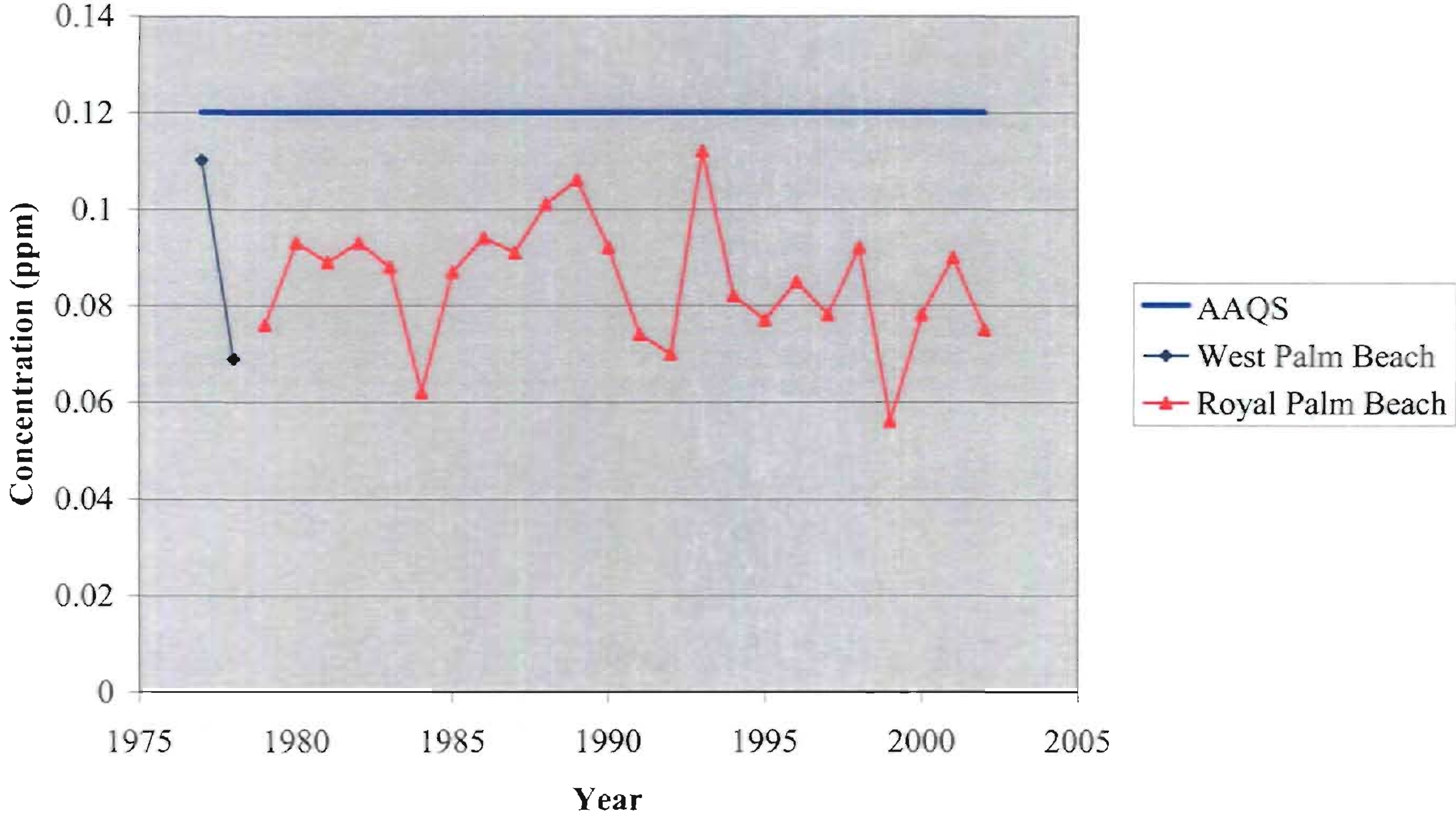
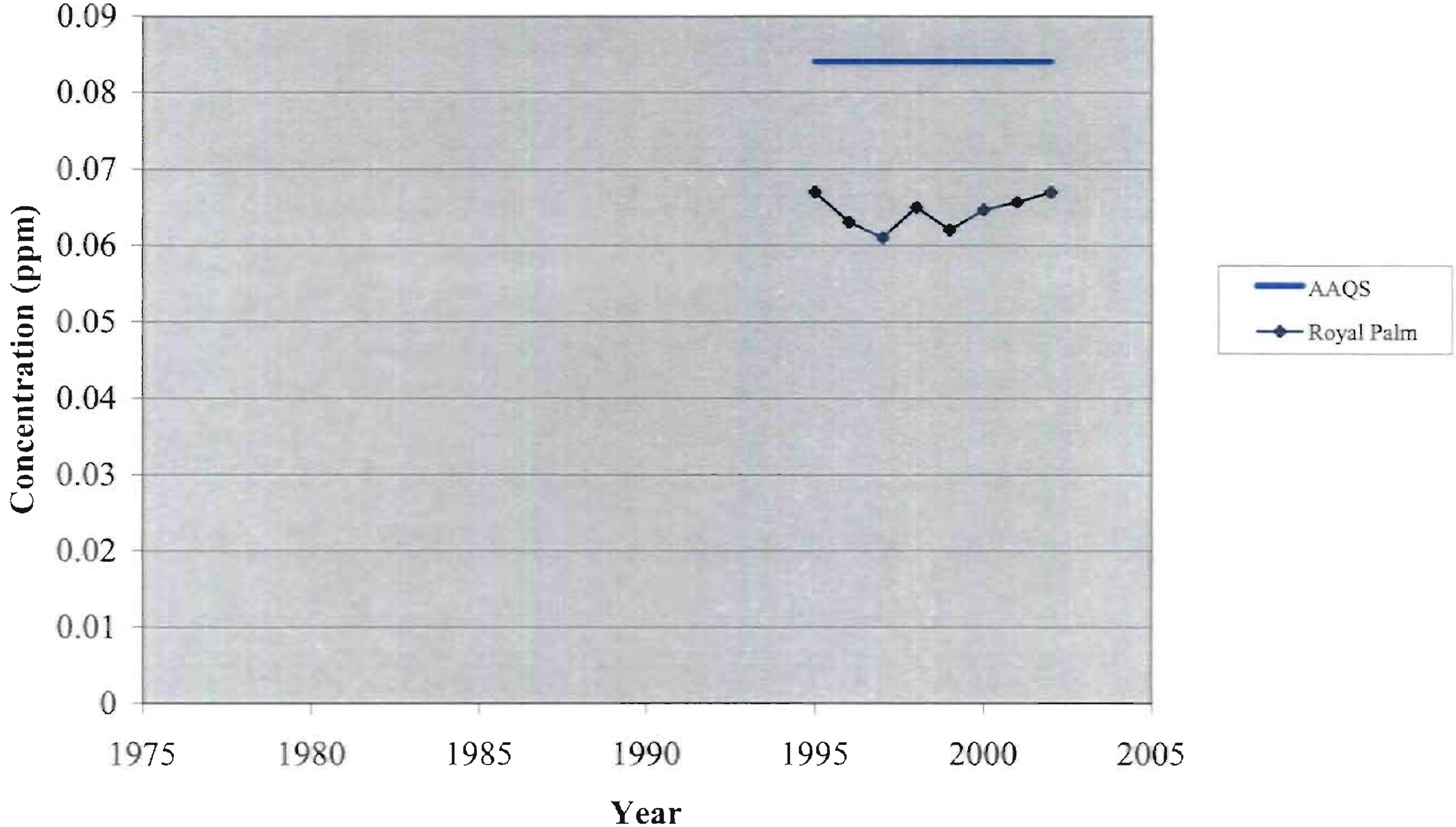


**Figure C-16 Measured 8-Hour Average Ozone Concentrations (3-Year Average of the 4th Highest Values) in Palm Beach County**



# United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

IN REPLY REFER TO:

May 1, 2003

N3615 (2350)

RECEIVED
MAY 14 2003
BUREAU OF AIR REGULATION

A.A. Linero, P.E., Administrator
Department for Environmental Protection
New Source Review Section
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

We have reviewed the U.S. Sugar Corporation's (U.S. Sugar) Prevention of Significant Deterioration (PSD) permit application for a modification to their Clewiston Sugar Mill and Refinery in Hendry County, Florida. The refinery is located approximately 102 kilometers north of Everglades National Park (NP), a Class I air quality area administered by the National Park Service (NPS). U.S. Sugar proposes to add a new 550,000 lb/hour, bagasse, natural gas, and oil-fired steam boiler to the existing Clewiston Sugar Mill and Refinery. Proposed addition of this boiler will cause emissions of nitrogen oxides ($NO_x$) to increase by 744 tons per year (TPY), sulfur dioxide to increase by 203 TPY, volatile organic compounds to increase by 203 TPY, and particulate matter to increase by 88 TPY.

Based on our review of the permit application, we do not anticipate that emission increases from the proposed modification will have a significant impact on sensitive resources at the Everglades NP. However, we do have the following comments concerning the Best Available Control Technology analysis section.

**Best Available Control Technology (BACT)**

*Particulate Matter:* U.S. Sugar proposes an electrostatic precipitator (ESP) at an emission rate of 0.026 lb/mmBtu. We agree with the choice of an ESP and with the proposed emission rate.

*Nitrogen Oxides:* U.S. Sugar concluded that over-fire air and "good combustion practices" represent BACT at an average emission rate of 0.22 lb/mmBtu. In its 1999 application to increase the permitted operating hours of its bagasse and #6 oil-fired Boiler #4, U.S. Sugar concluded that "good combustion practices" represent BACT because they were achieving an average emission rate of 0.08 lb/mmBtu. We believe that a new boiler should be able to control $NO_x$ emissions to levels no greater than demonstrated by boiler #4 burning the same fuel (i.e., 0.08 lb/mmBtu).

U.S. Sugar rejected Selective Non-catalytic Reduction (SNCR) based upon a cost-effectiveness of $1400 per ton of $NO_x$ removed. We suggest that $1400/ton may be economically feasible on the basis that many states use a cost-effectiveness threshold of $2000-$5000/ton for $NO_x$.

*Sulfur Dioxide:* U.S. Sugar proposed firing of 0.05% sulfur fuel oil as BACT. By 2006, the Environmental Protection Agency (EPA) will require that 80% of all on-road diesel fuel meet a sulfur limit of 0.01%, and by 2010, 100% of all on-road diesel fuel must meet that limit. Although those EPA limits will not directly apply to fuel oil burned in a boiler such as that proposed by U.S. Sugar, it is clear that 0.01% sulfur oil will be readily available by 2006. We are aware of at least four proposed combustion turbine projects in Virginia (Tenaska—Bear Garden, Tenaska-Fluvanna Co., Dynegy—Chickahominy Power, and ODEC-Louisa Co.) and one facility in Georgia (Southern Co.-Macintosh) that have proposed the use of fuel oil limited to 0.01% sulfur. U.S. Sugar should address the feasibility of using such a lower sulfur fuel oil in its BACT analysis. We request U.S. Sugar be required to purchase and use 0.01% sulfur oil no later than 2006.

In summary, we agree that ESP is BACT for particulate matter emissions. U.S. Sugar should lower their $NO_x$ limit to reflect actual capabilities of the new boiler; they should achieve emissions levels of 0.08 lb/mmBtu, no greater than emission levels demonstrated by boiler #4. U.S. Sugar should also consider the use of lower sulfur oil.

Thank you for involving us in the review of the PSD permit application for the modification to U.S Sugar's Clewiston Sugar Mill and Refinery. Please do not hesitate to contact me at (303) 969-2817 regarding future air quality matters involving the NPS.

Sincerely,

Darwin W. Morse
Environmental Protection Specialist
Policy, Planning and Permit Review Branch

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary


May 2, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: **Request for Additional Modeling Information**
Project No. 0510003-021-AC (PSD-FL-333)
Clewiston Sugar Mill and Refinery
Proposed New Boiler 8

Dear Mr. Raiola:

On April 2, 2003, the Department received your application and sufficient fee for an air permit to construct a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to support operations of the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The modeling information submitted with 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 below items require new calculations or revised modeling, please submit the new calculations or revised modeling, assumptions, reference material and appropriate revised pages of the application form.

1. The building information contained in the facility plot plan Attachment UC-FI-C2, Page 3 and the BPIP building, structure data and location data contained in the figures and information in Appendix K do not appear to match. Please indicate which of these is correct. In addition, please update the application with the correct, detailed building structure information used in the modeling to determine downwash impacts. This information should include building dimensions for all buildings used in the modeling analyses. In addition, please provide a detailed plot plan to scale of the facility showing the exact location of the modeling origin in meters and the location from this modeling origin of each building and stack. All stacks and buildings should be labeled. In addition, a grid with 50 meter spacing should be overlaid over this plot plan so that the information on the plot plan can be easily correlated with the information in the BPIP files.

2. Rule 62-212.400(5)(h) 5, F.A.C. requires the applicant to provide information relating to the air quality impact of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Please provide this information. The additional impacts section 7.0 does not adequately address this requirement.

3. Comments from EPA or NPS: The Department has provided copies of the PSD application for comment to EPA Region 4 and the National Park Service. If we receive specific comments, we will forward for your response.

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 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. now 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 850/921-8986.

Sincerely,

Cleveland G. Holladay
New Source Review Section

cc: Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. William A. Raiola
Vice President of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

**COMPLETE THIS SECTION ON DELIVERY**

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PS Form 3800, January 2001 See Reverse for Instructions

# Department of
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 25, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William A. Raiola, V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

Re: **Request for Additional Information**
Project No. 0510003-021-AC (PSD-FL-333)
Clewiston Sugar Mill and Refinery
Proposed New Boiler 8

Dear Mr. Raiola:

On April 2, 2003, the Department received your application and sufficient fee for an air permit to construct a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to support operations of the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. 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 below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Boiler 8: Boiler 8 will be a membrane wall boiler with balanced draft stoker, overfire air, rotating feeders, and pneumatic spreaders having the following specifications:

   - Steam Production: 550,000 lb/hour, 1-hour max. (500,000 lb/hour, 24-hour max.)
   - Steam Parameters: 600 psig @ 750° F (enthalpy = 1379 Btu/lb)
   - Feedwater Parameters: 800 psig @ 250° F (enthalpy = 218 Btu/lb)
   - Heat Input Rate: 1030 MMBtu/hour, 1-hour max. (936 MMBtu/hour, 24-hour max.)
   - Approximate Furnace Volume: 50,520 $ft^3$ (20,497 Btu/$ft^3$ heat release rate)
   - Design Thermal Efficiency: 62%
   - Stack Parameters: 13 feet diameter; 199 feet tall
   - Flue Gas: 330° F; 400,000 acfm @ 5.5% $O_2$ (225,000 dscfm @ 7% $O_2$)

   Please provide specific details describing how the bagasse feed rate and boiler heat input rate will be determined. Describe the mechanism used to adjust the air-to-fuel ratio. Describe the soot blowing procedures, frequency and the impacts on emissions. The application indicates that the flue gas oxygen content will be approximately 5.5%. What will be the normal operating range for the flue gas oxygen content? Will Boiler 8 be the primary boiler used to support the refinery operation during the milling off season? Will Boilers 7 and 8 normally operate at the same time during the refinery season?

2. Requested Fuels: Boiler 8 will fire the following fuels:

   - Primary Fuel: Bagasse (7.2 MMBtu/ton; 143 tons per hour)
   - Startup/Supplemental Fuel: Distillate oil (0.05% sulfur by wt.; 135 MMBtu/1000 gallons; 4161 gph)
   - Startup/Supplemental Fuel: Natural gas (1000 MMBtu/MMscf; 0.562 MMscf/hour)

Although U.S. Sugar has indicated a desire to fire natural gas as a startup fuel and a supplemental fuel, it does not appear that gas will be available in the Clewiston area within the next two years. Will the gas burners be installed during the initial construction of Boiler 8? A Department air construction permit may only cover the initial period to construct and test the unit in preparation for commercial operation. Does U.S. Sugar wish to pursue natural gas at this time?

3. Requested Capacity Restrictions: The application requests that the annual capacity factor for Boiler 8 be restricted to 75% by limiting the annual steam production to 3.6135 x $10^{+09}$ pounds per year (equivalent to 6,767,100 MMBtu/year). With the shutdown of Boiler 3, this allows the project to net out of PSD review for CO emissions. Fossil fuels will be limited to an annual capacity factor of less than 10%. This limit avoids certain requirements of NSPS Subpart Db. Please understand that a future relaxation of these restrictions will require a PSD applicability review as if the boiler were not yet constructed and may trigger other requirements.

4. CO and VOC Emissions: As mentioned previously, the project nets out of PSD review for CO emissions due to the restriction on annual capacity and the proposed CO standard of 0.38 lb/MMBtu, which is based on a 12-month rolling average. The application indicates that this standard was calculated by correcting to a flow rate of 225,000 dscfm @ 7% $O_2$ from the design flow rate of 203,180 dscfm @ 5.5% $O_2$ (which represents "actual" conditions). At 5.5% $O_2$, the hourly emission rate would be 321.5 lb/hour or 0.34 lb/MMBtu based on a 24-hour average. Please explain the correction to 7% $O_2$ before calculation of the emission rate based on heat input.

   The proposed EPA MACT standard for CO is 400 ppmvd @ 3% $O_2$. Based on the method provided in the application, the flow rate corrected to the MACT units would be 174,961 dscfm @ 3% $O_2$. The mass emission rate would be 277 lb/hour and the equivalent 24-hour emission rate based on heat input would be 0.30 lb/MMBtu. According to the proposed boiler MACT, Boiler 8 will be required to meet standards upon startup if the rule is final or no later than the date the MACT becomes final. Therefore, the Department intends to require that the new boiler be designed to achieve the proposed MACT CO work practice standard of 400 ppmvd @ 3% $O_2$ based on a 24-hour average. Until the MACT becomes final, this will likely be established as a "target level" of emissions that indicates good combustion practices are being employed. Please comment.

   The proposed VOC limit is 0.06 lb/MMBtu. The test data available for similar units indicates lower levels may be achievable. The application list VOC emission test data for Clewiston Boiler 7 and New Hope Power Boilers 1-3. VOC test data for Clewiston Boiler 7 shows the highest tested rate to be 0.114 lb/MMBtu with the next highest rate at 0.015 lb/MMBtu. The Department notes that the CO emission rate was 0.392 lb/MMBtu for the highest VOC rate and 0.287 lb/MMBtu for the next highest rate, which may indicate that the unit was not operating under the best combustion conditions. In addition, it is unclear whether the VOC emission rate includes methane or ethane emissions, which are not regulated as VOC. Similarly, the highest tested VOC emission rate for New Hope Power Boilers 1-3 was 0.02 lb/MMBtu. Based on this information, the Department is considering a VOC standard of 0.03 lb/MMBtu based on good combustion practices. Please comment.

   **CO CEMS**: The Department intends to require a continuous emissions monitor to measure and record CO emissions.

5. Particulate Matter Controls

   **Wet Cyclone**: Please provide a description, a conceptual diagram and additional design details of the wet cyclone scrubber. What will be the approximate water injection rate? Will this rate change subject to load conditions? Please provide the results of any inlet/outlet testing performed for the similar scrubber installed on Boiler 7.

   **ESP**: The application indicates that the vendor has not yet been selected. Which vendors are being considered for the project? Will this be a dry, negative corona plate ESP? Please provide reasonable assurance that the proposed ESP can achieve the propose emission standard. (For example, preliminary estimates for the following design parameters: collection plate area ($ft^2$); specific collection area (SCA, $ft^2$ per 1000 $ft^3$/minute); length and height of each field (ft); aspect ratio (L/H); particle migration velocity (w); field voltage; current, and sparking rate.) Will there be one electrical transformer-rectifier (T-R) set for each of the nine fields? Please describe the rapping system used to remove collected ash from the ESP plates including storage and handling. During startup, identify parameters that indicate the proper time to energize the ESP. Approximately how long is it from initial fuel firing to energizing the ESP?

**COMS**: Provide a justification for the Alternate Sampling Procedure (ASP) requested in lieu of the continuous opacity monitor, which is required by NSPS Subpart Db. The Department will forward your request to EPA Region 4 for a determination, as this is a federal requirement. Please note that the Department may require a continuous opacity monitor as part of a continuous demonstration of compliance with the BACT permit limits.

6. Sulfur Dioxide and Sulfuric Acid Mist Controls: The Department is considering an $SO_2$ standard of 0.05 lb/MMBtu for all combinations of fuel firing. This emission level reflects previous BACT determinations for a variety of combustion processes that specify ultra-low sulfur distillate oil (0.05% sulfur by weight), which is also equivalent to 0.05 lb/MMBtu of heat input. Based on available information for bagasse boilers, this is achievable for the proposed unit. Notwithstanding any underlying state or federal requirements to install an $SO_2$ CEMS, the Department is considering the following for demonstrating compliance: quarterly $SO_2$ stack testing for the first year; monthly sampling and analysis of bagasse for fuel sulfur content for first year; if first year shows satisfactory compliance the stack testing may be reduced to annual tests and bagasse sampling to quarterly analysis. Please comment.

7. Controls for Nitrogen Oxides

The proposed NOx standard of 0.22 lb/MMBtu based on good combustion practices does not reflect the maximum level of control for similar solid fuel fired boilers. Even at a lower level, it is likely that an add-on control technology will be cost-effective.

**SCR**: The Department is not convinced that SCR is technically infeasible due to poisoning issues. There are many coal-fired boilers in the U.S. and there are many municipal waste combustors in Europe that successfully employ SCR. Please provide information to support the impacts of catalyst poisoning. Compare and comment on expected poison levels from firing bagasse with that of firing coal and/or municipal solid waste. In addition, obtain at least one cost quote specifically for this project from an SCR vendor and submit an economic cost analysis. Provide to the Department the information given to the vendor as the basis for the design.

**SNCR**: The Department is aware of several wood fired boilers, wood/bagasse boilers, and wood/municipal waste combustors that successfully employ SNCR to reduce NOx emissions by at least 40%. It is clearly a cost effective technique and there are no apparent technical reasons for rejecting this technology. Please provide any additional information on SNCR you would like the Department to consider in making a BACT determination.

**NOx CEMS**: Regardless of the technology employed, the Department intends to require a continuous emissions monitoring system for NOx emissions.

8. Boiler MACT: On January 13, 2003, EPA proposed Subpart DDDDD, which establishes maximum achievable control technology (MACT) requirements for hazardous air pollutants (HAPs) from industrial, commercial, and institutional boilers and process heaters. The application indicates that Boiler 8 is not expected to be a major source of HAP emissions and will not be subject to the MACT regulations for new boilers. If the proposed rule becomes final as currently written, the Department believes that Boiler 8 will be subject to the final MACT standards either: upon startup (if the rule becomes final before startup) or when the rule becomes final (if start up occurs before the rule becomes final). The Department intends to require that Boiler 8 be designed to achieve the proposed standards. Please comment.

9. Bagasse Handling System: For any new dust collectors being added as part of this project, please provide the vendor's predicted outlet emission rate (grains/acf), flow rate range (acfm), and control efficiency.

10. Refinery Operations: Is U.S. Sugar requesting a relaxation of any operational restrictions or emission standards for existing emission units at the refinery? Please identify any such relaxations and quantify the emissions impacts as necessary.

11. CAM Plan: Please be aware that a CAM plan will be required for each pollutant with potential emission greater than 100 tons per year (CO, NOx, $SO_2$, and VOC) as part of the Title V application to incorporate the operation of Boiler 8.

12. Air Quality Modeling Review: The Department is currently reviewing the air quality modeling analysis provided in support of the proposed project. Any additional information will be requested on or before May 2, 2003.

13. Comments from EPA or NPS: The Department has provided copies of the PSD application for comment to EPA Region 4 and the National Park Service. If we receive specific comments, we will forward for your response.

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 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. now 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
New Source Review Section

cc: Mr. David Buff, Golder Associates
Mr. Ron Blackburn, SD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

**SENDER:** *COMPLETE THIS SECTION*

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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation - Clewiston Sugar Mill & Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

*COMPLETE THIS SECTION ON DELIVERY*

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PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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*Sent To* William A. Raiola

*Street, Apt. No.; or PO Box No.* 111 Ponce DeLeon Avenue

*City, State, ZIP+4* Clewiston, FL 33440

PS Form 3800, January 2001 See Reverse for Instructions

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 3, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
Air Quality Division
National Park Service
P.O. Box 25287
Denver, CO 80225

Re: New Application for a PSD Air Construction Permit
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler No. 8
Project No. 0510003-021-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for a modification to an existing PSD facility. U.S. Sugar Corporation proposes to add a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The proposed boiler will fire primarily bagasse with ultra-low sulfur distillate oil and natural gas used for startup, shutdown and as a supplemental fuel. PSD applicability for the project is based on a netting analysis that includes the shutdown of existing Boiler No. 3, a 130,000 lb/hour steam boiler (265 MMBtu/hour). Based on a preliminary review, the applicant recommends the following control technologies for the PSD-significant pollutants:

| Pollutant* | Applicant's Control Technology Recommendation |
|---|---|
| NOx | Boiler Design and Good Combustion Practices |
| PM/PM10 | Wet Cyclone Followed by an ESP |
| SAM | Low Sulfur Fuels (Bagasse, Natural Gas, and Ultra-Low Sulfur Distillate Oil) |
| SO2 | Low Sulfur Fuels (Bagasse, Natural Gas, and Ultra-Low Sulfur Distillate Oil) |
| VOC | Boiler Design and Good Combustion Practices |

* Based on the applicant's netting analysis, the project is not subject to PSD preconstruction review for CO, lead, mercury, or fluorides. The applicant also believes that the project is not subject to MACT.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Al Linero, Manager
New Source Review Section
Florida Department of Environmental Protection

Enclosure: New PSD Application

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 3, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jeaneanne M. Gettle, Acting Chief
Air Planning Branch, Air Permits Section
U.S. EPA Region 4
Atlanta Federal Center
61 Forsyth Street
Atlanta, GA 30303-8960

Re: New Application for a PSD Air Construction Permit
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler No. 8
Project No. 0510003-021-AC

Dear Ms. Gettle:

Enclosed for your review and comment is an application for a modification to an existing PSD facility. U.S. Sugar Corporation proposes to add a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The proposed boiler will fire primarily bagasse with ultra-low sulfur distillate oil and natural gas used for startup, shutdown and as a supplemental fuel. PSD applicability for the project is based on a netting analysis that includes the shutdown of existing Boiler No. 3, a 130,000 lb/hour steam boiler (265 MMBtu/hour). Based on a preliminary review, the applicant recommends the following control technologies for the PSD-significant pollutants:

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| PM/$PM_{10}$ | Wet Cyclone Followed by an ESP |
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| SO2 | Low Sulfur Fuels (Bagasse, Natural Gas, and Ultra-Low Sulfur Distillate Oil) |
| VOC | Boiler Design and Good Combustion Practices |

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Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Al Linero, Manager
New Source Review Section
Florida Department of Environmental Protection

Enclosure: New PSD Application

# Department of
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 3, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ron Blackburn
Air Resources Section
South District Office
Florida Department of Environmental Protection
2295 Victoria Avenue, Suite 364
Fort Myers, FL 33901-3381

Re: New Application for a PSD Air Construction Permit
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler No. 8
Project No. 0510003-021-AC

Dear Mr. Blackburn:

Enclosed for your review and comment is an application for a modification to an existing PSD facility. U.S. Sugar Corporation proposes to add a new 550,000 lb/hour steam boiler (1031 MMBtu/hour) to the existing Clewiston Sugar Mill and Refinery in Hendry County, Florida. The proposed boiler will fire primarily bagasse with ultra-low sulfur distillate oil and natural gas used for startup, shutdown and as a supplemental fuel. PSD applicability for the project is based on a netting analysis that includes the shutdown of existing Boiler No. 3, a 130,000 lb/hour steam boiler (265 MMBtu/hour). Based on a preliminary review, the applicant recommends the following control technologies for the PSD-significant pollutants:

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| SO2 | Low Sulfur Fuels (Bagasse, Natural Gas, and Ultra-Low Sulfur Distillate Oil) |
| VOC | Boiler Design and Good Combustion Practices |

* Based on the applicant's netting analysis, the project is not subject to PSD preconstruction review for CO, lead, mercury, or fluorides. The applicant also believes that the project is not subject to MACT.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Al Linero, Manager
New Source Review Section
Florida Department of Environmental Protection

Enclosure: New PSD Application

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*Printed on recycled paper.*

**Golder Associates Inc.**

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

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APR 01 2003

BUREAU OF AIR REGULATION

March 31, 2003

0237619

Florida Department of Environmental Protection
New Source Review Section
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

Attention: Alvaro A. Linero, P.E., Administrator

RE: U.S. SUGAR CORPORATION, CLEWISTON MILL
PSD PERMIT APPLICATION FOR THE PROPOSED BOILER NO. 8

Dear Mr. Linero:

Enclosed please find six (6) copies of the Prevention of Significant Deterioration (PSD) application for the proposed Boiler No. 8 at the Clewiston Mill.

Please feel free to call me at (352) 336-5600 ext. 545 if you have any questions.

Sincerely,

GOLDER ASSOCIATES INC.

Robert C. McCann Jr for

David A. Buff, P.E., Q.E.P.
Principal Engineer

DAB/jkw

Enclosures

cc: D. Griffin, U.S. Sugar

P:\Projects\2002\0237619 US Sugar\4\4.1\L033103.doc

# Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

September 1, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Project No. 0510003-040-AC
U.S. Sugar Corporation - Clewiston Sugar Mill and Refinery
Approval of Request to Cease Continuous Monitoring the Cyclone Pressure Drop on Boiler 8

Dear Mr. Smith:

In a letter to EPA Region 4 dated May 17th, 2006, U.S. Sugar Corporation requested approval to cease continuous monitoring the pressure drop across the pair of wet cyclones on Boiler 8. The wet cyclones are used to remove sand from the flue gas to prevent erosion of downstream equipment such as the induced draft (ID) fan and electrostatic precipitator (ESP). Although water removes some particulate matter from the flue gas, its main function is to wash the cyclones free of collected dust. The primary removal mechanism is cyclonic flow and changes in flue gas direction. NESHAP Subpart DDDDD requires continuous monitoring of the pressure drop and flow rate for scrubbers that control particulate matter. Installed as "pre-controls" before the ESP, the wet cyclones are static devices with no moving parts. The plant has no direct control over the cyclone pressure drop, which is a function of the exhaust flow rate and unit load on the boiler. Continuously monitoring and recording this parameter is burdensome and provides limited useful information with regard to ensuring compliance with the particulate matter standard.

As a related issue, the Department recently issued an air construction permit authorizing the installation of a third cyclone as a pre-control device for Boiler 8. The additional cyclone is "dry" and will lower velocities across the existing wet cyclones to prevent water carryover into the existing ESP. The Department understands that U.S. Sugar plans to conduct additional particulate matter testing with no water to the existing wet cyclones to demonstrate compliance as "dry" cyclones. Depending on test results, U.S. Sugar may submit a subsequent request to cease continuous monitoring of the water flow rate to the wet cyclones.

**Determination**: In July of 2006, the Department contacted EPA Region 4 regarding the status of this request. Subsequent conversations indicate that EPA Region 4 considers this request to be a "minor change" to the NESHAP Subpart DDDDD monitoring provisions, which are handled by the states. Based on the information provided, the Department agrees with U.S. Sugar's position and authorizes U.S. Sugar to cease continuous monitoring of the pressure drop across the wet cyclones on Boiler 8. Please be advised that Permit No. PSD-FL-333B requires the following monitoring for these wet cyclones, "At least once each 8-hour work shift, the flow rate and pressure drop shall be observed and recorded in a written log." This permitting determination is issued pursuant to Chapter 403, Florida Statutes.

**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. 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.

This determination is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this action will not be effective until further order of the Department.

**Mediation**: Mediation is not available in this proceeding.

**Appeals**: Any party to this order has the right to seek judicial review of it under Section 120.68, F.S., 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 thirty (30) days after this order is filed with the clerk of the Department.

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

Executed in Tallahassee, Florida.

Trina J Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this determination was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9/1/06 to the persons listed below.

Mr. Neil Smith, U.S. Sugar*
Mr. Don Griffin, U.S. Sugar
Mr. Peter Briggs, U.S. Sugar
Mr. David Buff, Golder Associates Inc.
Mr. Ron Blackburn, SD Office
Mr. Joydeb Majumder, EPA Region 4

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 9/1/06
(Clerk) (Date)

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1. Article Addressed to:

Mr. Neil Smith, 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 Rachel Felton ☐ Agent ☐ Addressee

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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 ūK

**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

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MAY 18 2006

BUREAU OF AIR REGULATION

May 17, 2006

063-7563

U.S. Environmental Protection Agency, Region 4
61 Forsythe St. SW 9th
Atlanta, GA 30303

Attention: Mr. Doug Neeley

RE: UNITED STATES SUGAR CORPORATION
CONTROL EQUIPMENT PARAMETER DELETION - PRESSURE DROP
BOILER NO. 8 WET CYCLONES

Dear Mr. Doug Neeley:

United States Sugar Corporation (U.S. Sugar) is requesting that the pressure drop operating limit for the two wet cyclone sand separators on Boiler No. 8 be revised to reflect actual operation. More specifically, U.S. Sugar is requesting to delete pressure drop as a control equipment parameter under 40 CFR 63, Subpart Db (Boiler MACT), which requires operating limits be determined for wet scrubbers.

The control equipment on Boiler No. 8 is best described as a wet cyclone sand separator and not a traditional wet scrubber. Its main function is to provide protection for downstream equipment [(i.e., inside diameter (ID) fan and electrostatic precipitator (ESP)] against erosion wear from fine sand particles contained in the bagasse fuel. Once fired in the furnace, these sand particles become entrained in the flue gas, and experience has shown that if this sand is not removed before entering the ID fan, the fan's rotating parts will be damaged due to premature erosion.

The sand-removal principle of the wet cyclones is a combination of velocity/momentum change and also water droplet/sand particle coalescing. As the gas enters the separator vessel, it passes through a water-spray section, evaporatively cools, and decreases in velocity, allowing sand to fallout.

Next, the gas changes direction and spirals upward through the vessel. Coarse abrasive ash and sand particles adhere to the periphery of the vessel, from where they are washed down to the discharge hopper. While the unit does include spray nozzles, the water spray not only 'scrubs' the sand from the gas stream, but is also used to wash the vessel out on a continuous basis (the mill uses a wet sluice system for ash handling). The primary method of sand (particulate matter) collection is gas velocity reduction and sand particle/gas momentum change within the separator vessel. The water scrubbing action is secondary to the sand collection.

Pressure drop is one indicator parameter for wet scrubbers under the Boiler MACT rule (the other parameter is water flow rate). However, this requirement is believed to be for traditional wet scrubbers (i.e., venturi, packed bed, etc.). For the wet cyclones on Boiler No. 8, the collection efficiency of particulate matter is not primarily related to pressure drop. The wet cyclones are static devices (i.e., no moving parts); therefore pressure drop is primarily a function of the flue gas flow rate through the cyclone (i.e., the velocity through the cyclone).

As a result, pressure drop varies as the steam load changes on Boiler No. 8. U.S. Sugar has found that the pressure drop is correlated with steam production (i.e., boiler load). Plots of the wet cyclone pressure drop versus boiler load for both wet cyclones are attached as Figures 1 and 2. It is also noted that U.S. Sugar has very little control, if any, over the pressure drop across the wet cyclones. This presents a problem when performance testing under the Boiler MACT rule and setting minimum pressure drop limits. The Boiler MACT testing is performed at close to maximum load, when the pressure drop across the cyclones is highest. However, under normal operation the boiler load can range from 25 percent up to 100 percent of maximum, with corresponding changes (reductions) in pressure drop. This causes deviations for the pressure drop parameter under the Boiler MACT rules.

U.S. Sugar could conduct Boiler MACT performance testing over a range of load conditions and develop minimum pressure drop values as a function of load. However, the wet cyclone is designed to maintain efficiency over the range of operating loads of the boiler. Developing minimum pressure drop values as a function of load could require extensive testing, and even such testing may not reflect all conditions that may affect pressure drop (i.e., air density, relative humidity, etc.). As stated previously, U.S. Sugar has no way of controlling the pressure drop that the wet cyclones experience.

Based on the foregoing discussion, it is requested that pressure drop be deleted as a control equipment parameter under the Boiler MACT rules for the Boiler No. 8 wet cyclones. Scrubber water flow rate will continue to be monitored and subject to the requirements of the MACT rule.

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
Jeff Koerner, FDEP South District
Don Griffin
Peter Briggs

Enclosures

DB/CB/all

Y:\Projects\2006\0637563 USSC Boilers 1 & 2\4.1\051706 Pressure Drop\L051706.doc

**FIGURE 1**
**SCRUBBER 1 - PRESSURE DROP VS. STEAM PRODUCTION**

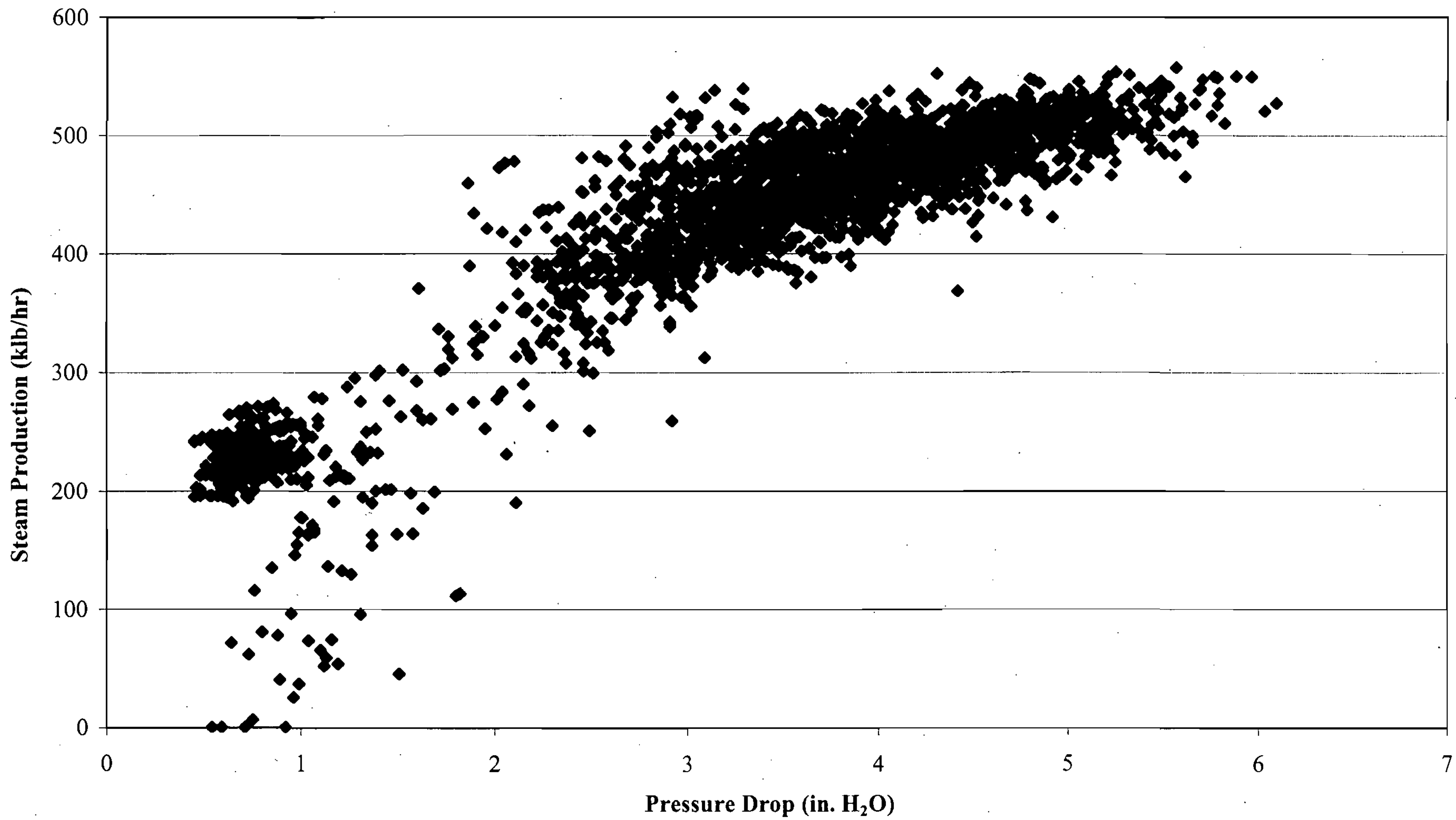
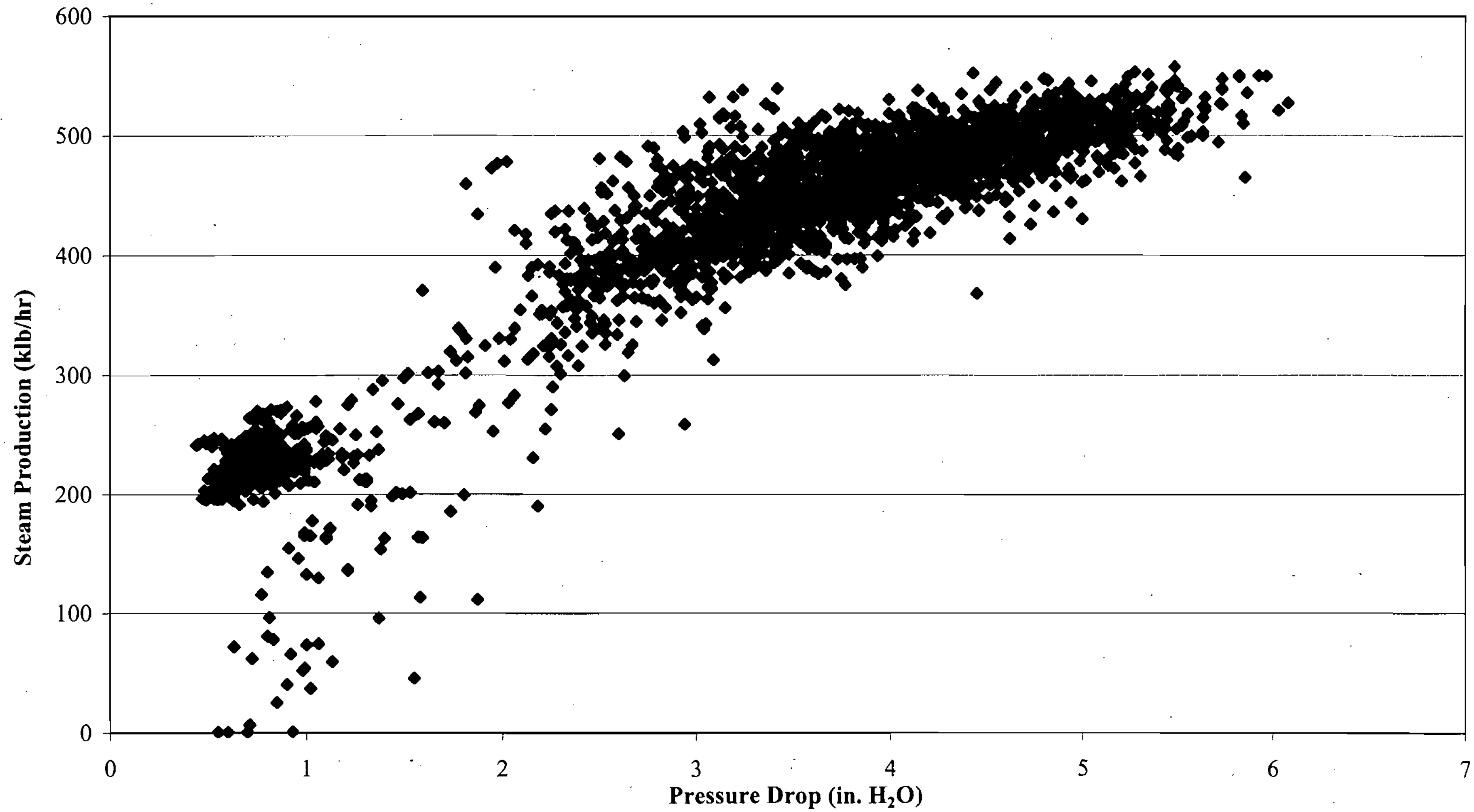


**FIGURE 2**
**SCRUBBER 2 - PRESSURE DROP VS. STEAM PRODUCTION**



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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation - Clewiston Sugar Mill & Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by (*Please Print Clearly*)

B. Date of Delivery 4-28-03

C. Signature
X Audrea Sal[illegible]
☐ Agent
☐ Addressee

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William A. Raiola
*Street, Apt. No.; or PO Box No.*
111 Ponce DeLeon Avenue
*City, State, ZIP+4*
Clewiston, FL 33440

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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6/18/03

C. Signature

X Andrea Soltz ☐ Agent ☐ Addressee

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*Sent To* William A. Raiola
*Street, Apt. No.; or PO Box No.* 111 Ponce DeLeon Ave.
*City, State, ZIP+4* Clewiston, FL 33440

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1. Article Addressed to:

Mr. William A. Raiola
Vice President of Sugar Processing Operations
United States Sugar Corporation
Clewiston Sugar Mill and Refinery
111 Ponce DeLeon Avenue
Clewiston, FL 33440

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by *(Please Print Clearly)* A. Socls

B. Date of Delivery 5-5-03

C. Signature X [signature]

☒ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

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*City, State, ZIP+4*
Clewiston, FL 33440

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1. Article Addressed to:

Mr. William A. Raiola
V.P. of Sugar Processing Operations
United States Sugar Corporation
Post Office Drawer 1207
Clewiston, FL 33440-1207

**COMPLETE THIS SECTION ON DELIVERY**

A. Received by (*Please Print Clearly*) L. Harris

B. Date of Delivery 9-29-03

C. Signature
X L. Harris

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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3. Service Type
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4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2. 7001 0320 0001 3692 6068

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*City, State, ZIP+4* Clewiston, FL 33440-1207

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**PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Permit No. 0510003-021-AC

U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery
Proposed New Boiler 8 Project
Hendry County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to U.S. Sugar Corporation (applicant) to construct the new Boiler 8 project at the existing Clewiston Sugar Mill and Refinery located in Hendry County, Florida. The applicant's authorized representative is Mr. William A. Raiola, V.P. of Sugar Processing Operations. The applicant's mailing address is United States Sugar Corporation, Clewiston Sugar Mill and Refinery, 111 Ponce DeLeon Avenue, Clewiston, FL 33440.

The applicant proposes to construct a spreader stoker boiler with a maximum continuous steam production rate of 500,000 pounds per hour to support the sugar mill and refinery operations of the existing plant. The boiler will fire bagasse as the primary fuel and distillate oil as a restricted alternate fuel for startup and supplemental uses. As part of the project, existing Boiler 3 will be permanently shut down and the bagasse handling system will be modified to accommodate Boiler 8. Actual emissions of several small existing miscellaneous activities in the mill and refinery may also occur.

The existing Clewiston sugar mill and refinery is located in Hendry County, which is in area that is currently in attainment with (or designated as unclassifiable for) all pollutants subject to state and federal Ambient Air Quality Standards. The plant is a major facility with respect to the Prevention of Significant Deterioration (PSD) of Air Quality as defined in Rule 62-212.400, F.A.C. Based on the application, the project will result in the following net potential increases in emissions in terms of "tons per year" (TPY): 55 TPY of carbon monoxide (CO); 0.8 TPY of fluorides (Fl); 0.1 TPY of lead (Pb); 90 pounds per year of mercury (Hg); 431 TPY of nitrogen oxides (NOx); 62 TPY of particulate matter (PM/PM10); 10 TPY of sulfuric acid mist (SAM); 157 TPY of sulfur dioxide (SO2); and 168 TPY of volatile organic compounds (VOC). Emissions of NOx, PM/PM10, SAM, SO2, and VOC exceed the PSD significant emission rates defined in Table 62-212.400-2, F.A.C. Therefore, the project is subject to PSD preconstruction review for these pollutants.

In accordance with Rule 62-212.400, F.A.C., the draft permit includes emissions standards that represent the Department's preliminary determination of the Best Available control Technology (BACT) for emissions of nitrogen oxides, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions of nitrogen oxides will be reduced by a urea-based selective non-catalytic reduction (SNCR) system. Particulate matter emissions will be controlled by wet cyclone collectors followed by an electrostatic precipitator (ESP). The boiler design with good combustion and operating practices will be used to minimize emissions of carbon monoxide and volatile organic compounds. Very low sulfur fuels will be used minimize the potential for emissions of sulfuric acid mist and sulfur dioxide. Emissions of nitrogen oxides and carbon monoxide will be continuously monitored. To minimize fugitive particulate matter from the bagasse handling system, gagasse conveyors will be enclosed and dust collectors will be installed on the conveyor transfer points.

As part of the required PSD preconstruction review, the Department reviewed the applicant's air quality analysis conducted for each PSD-significant pollutant. The air quality analysis showed no significant impacts from the project for any pollutant. The analysis provides the Department with reasonable assurance that the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standards.

The Department will issue the Final Permit with the proposed conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stoen Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant must be filed within fourteen (14) days of receipt of the notice of intent. 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 within fourteen (14) days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Physical Address: Suite 4, 111 S. Magnolia Drive
Mailing Address: 2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400
Telephone: 850-488-0114

Florida Department of Environmental Protection
South District Office
Air Resources Section
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901-3381
Telephone: 239-332-6975

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's project engineer for additional information at the address and phone numbers listed below.
419884 CGS 10/16/03

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1. Article Addressed to:

Mr. William A. Raiola
Vice President of Sugar Processing Operations
United States Sugar Corporation
111 Ponce DeLeon Avenue
Clewiston, FL 33440

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by *(Please Print Clearly)* Lufonda Hammond
B. Date of Delivery 1-24

C. Signature
X Lafonda Hammond
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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111 Ponce DeLeon Avenue
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Clewiston, FL 33440

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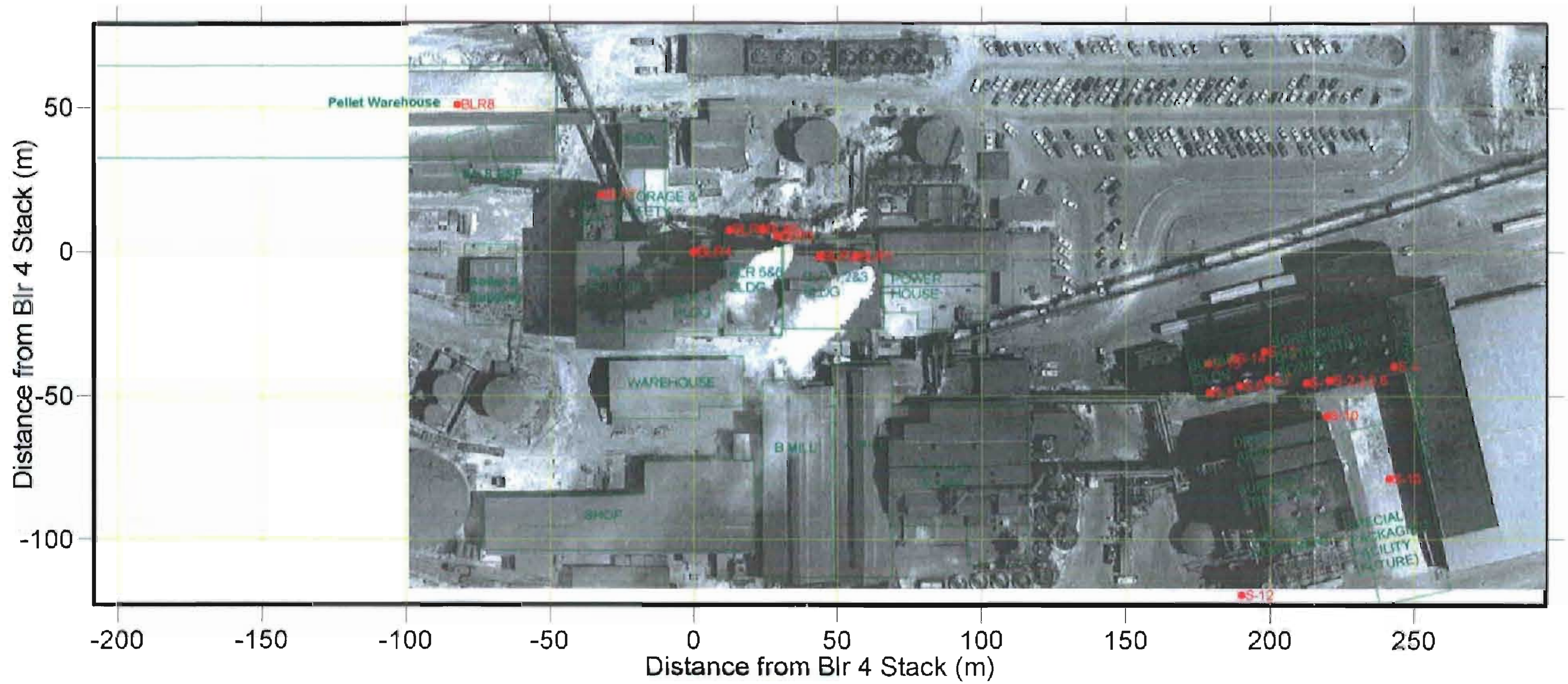

Pellet Warehouse
BLR8
WAREHOUSE
B MILL
SHOP
POWER HOUSE
S-12
Distance from Blr 4 Stack (m)
Distance from Blr 4 Stack (m)
50
0
-50
-100
-200
-150
-100
-50
0
50
100
150
200
250

Table 2-2. Maximum Short-Term Emissions for Boiler No. 8, U. S. Sugar Clewiston

| Regulated Pollutant | Bagasse Emission Factor (lb/MMBtu) | Bagasse Ref. | Bagasse Activity Factor (MMBtu/hr) | Bagasse Maximum Emissions (lb/hr) | No. 2 Fuel Oil Emission Factor (lb/MMBtu) | No. 2 Fuel Oil Ref. | No. 2 Fuel Oil Activity Factor (MMBtu/hr) | No. 2 Fuel Oil Maximum Emissions (lb/hr) | Natural Gas Emission Factor (lb/MMBtu) | Natural Gas Ref. | Natural Gas Activity Factor (MMBtu/hr) | Natural Gas Maximum Emissions (lb/hr) | Maximum Emissions for any fuel (lb/hr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Particulate (Total/$PM_{10}$) | | | | | | | | | | | | | |
| --3-hr Average | 0.026 | (1) | 1,030 | 26.8 | 0.026 | (1) | 562 | 14.61 | 0.0076 | (8) | 562 | 4.27 | 26.8 |
| --24-hr Average | 0.026 | (1) | 936 | 24.3 | | | | | | | | | 24.3 |
| Sulfur Dioxide | | | | | | | | | | | | | |
| --3-hr Average | 0.17 | (2) | 1,030 | 175.1 | 0.05 | (7) | 562 | 28.10 | 0.006 | (8) | 562 | 3.37 | 175.1 |
| --24-hr Average | 0.10 | (2) | 936 | 93.6 | -- | | -- | -- | -- | | -- | -- | 93.6 |
| Nitrogen Oxides | | | | | | | | | | | | | |
| --3-hr Average | 0.28 | (3) | 1,030 | 288.4 | 0.28 | (3) | 562 | 157.36 | 0.28 | (3) | 562 | 157.36 | 288.4 |
| --24-hr Average | 0.28 | (3) | 936 | 262.08 | -- | | -- | -- | -- | | -- | -- | 262.08 |
| Carbon Monoxide | | | | | | | | | | | | | |
| --1-hr Maximum | 6.5 | (4) | 1,030 | 6,695.0 | 0.036 | (10) | 562 | 20.2 | 0.084 | (8) | 562 | 47.208 | 6,695.0 |
| --8-hr Maximum | 4.5 | (4) | 1,030 | 4,635.0 | -- | | -- | -- | -- | | -- | -- | 4,635.0 |
| VOC | 0.06 | (3) | 1,030 | 61.8 | 0.0014 | (10) | 562 | 0.79 | 0.0055 | (8) | 562 | 3.09 | 61.80 |
| Sulfuric Acid Mist | | | | | | | | | | | | | |
| --3-hr Average | 0.0104 | (5) | 1,030 | 10.72 | 0.0015 | (5) | 562 | 0.8430 | 3.68E-04 | (5) | 562 | 0.21 | 10.72 |
| --24-hr Average | 0.0061 | (5) | 936 | 5.73 | -- | | -- | -- | -- | | -- | -- | 5.73 |
| Lead | 3.8E-05 | (6) | 1,030 | 0.039 | 9.0E-06 | (10) | 562 | 5.1E-03 | 5.0E-07 | (8) | 562 | 2.8E-04 | 0.039 |
| Mercury | 1.4E-05 | (6) | 1,030 | 0.0144 | 3.0E-06 | (10) | 562 | 1.7E-03 | 2.6E-07 | (8) | 562 | 1.5E-04 | 0.0144 |
| Fluorides | 6.0E-04 | (7) | 1,030 | 0.618 | -- | | -- | -- | -- | | -- | -- | 0.62 |

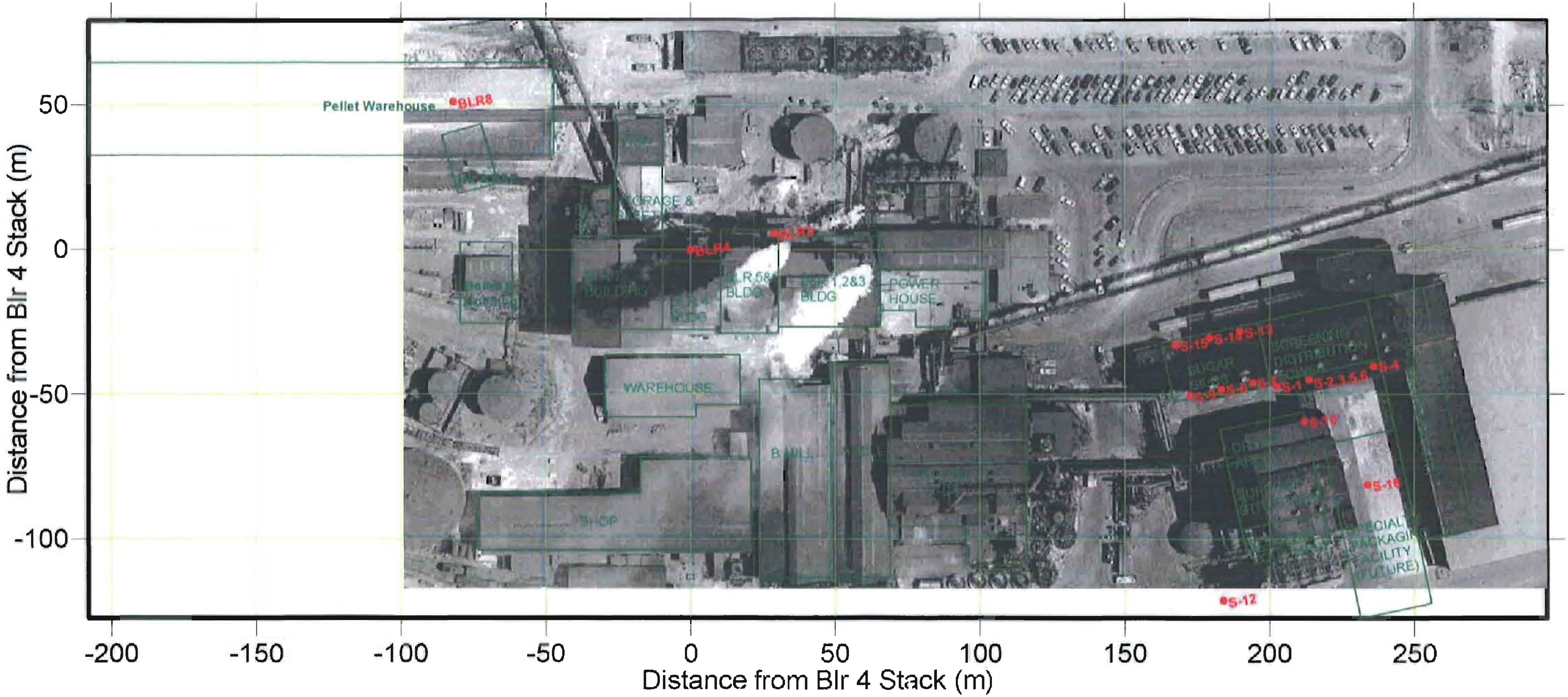
References:

1. Proposed BACT limit.
2. 3-hr avg. based on permit limit for Boiler No.7. The 24-hr avg. is based on stack test data for Boiler No. 7.
3. Based on Boiler No. 7 test data.
4. Represents startup or wet fuel conditions.
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.
7. Based on maximum of stack tests from Okeelanta cogen when burning bagasse only.
8. Based on AP-42 Section 1.4 for natural gas combustion:

| | | | |
|---|---|---|---|
| PM (total): | 7.6 lb/$10^6$ scf | VOC: | 5.5 lb/$10^6$ scf |
| $SO_2$: | 0.6 lb/$10^6$ scf | Mercury: | 2.6E-04 lb/$10^6$ scf |
| CO: | 84 lb/$10^6$ scf | Lead: | 0.0005 lb/$10^6$ scf |

9. Based on use of No. 2 fuel oil with a maximum of 0.05% sulfur.
10. 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 |




Facility Plot Plan
U.S. Sugar – Boiler No. 8

Source: Golder, 2003.

Golder Associates

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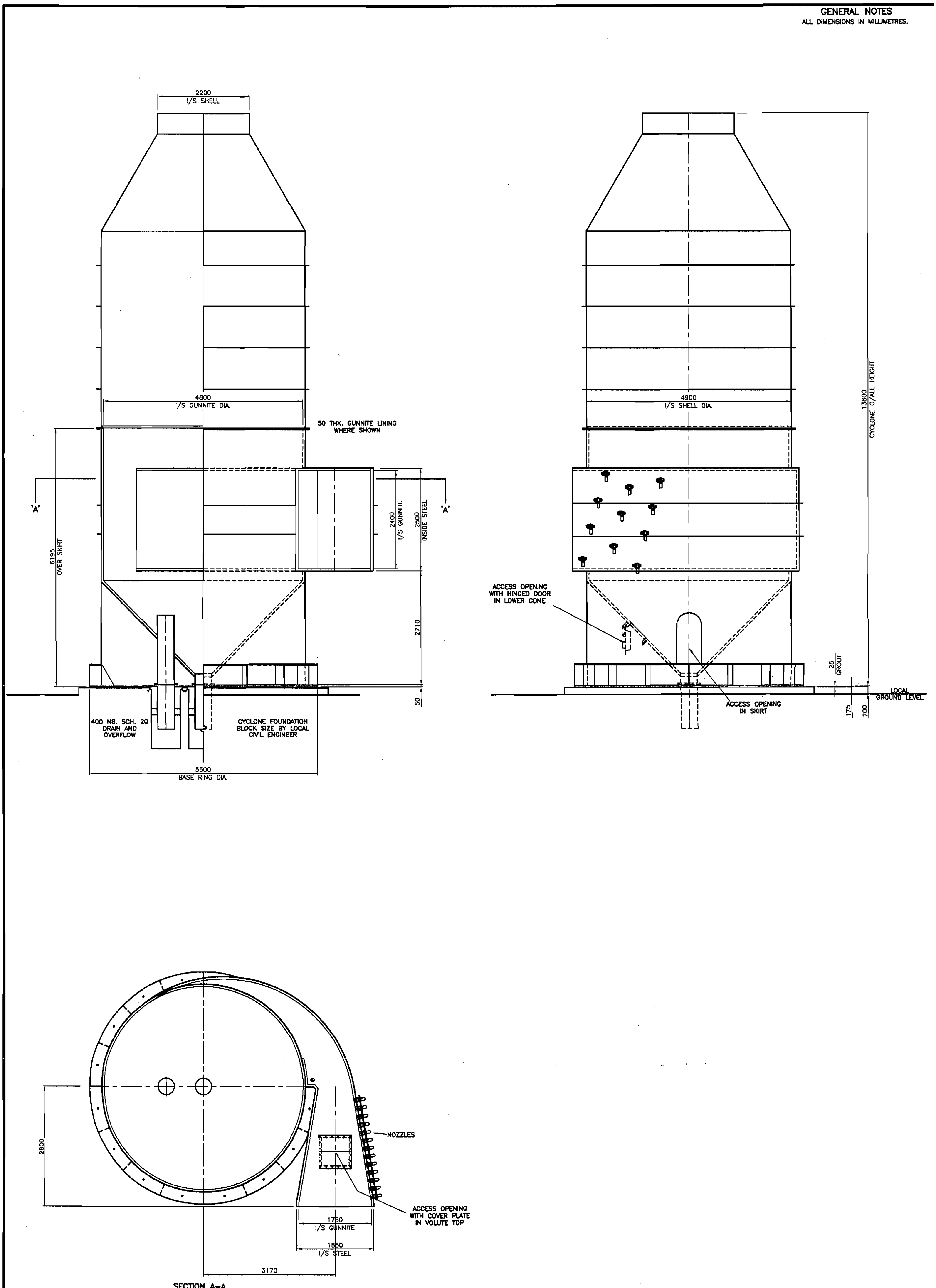


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**U.S. SUGAR CORPORATION – CLEWISTON**

**PRELIMINARY ARRANGEMET WET CYCLONE**

Thermal Energy Systems

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