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Golder Associates

RECEIVED
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BUREAU OF AIR REGULATION

October 28, 2003

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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\41\L102803\L102803.doc
G. Harley, EPA
G. 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.

General Conditions

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.]

SECTION 4. APPENDIX D

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~~ ~~(Equivalent: 363 ppmvd @ 7% O_2)~~ 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 ~~(Equivalent: 81 ppmvd @ 7% O_2)~~ [initial demonstration standard: subsequent compliance based on CEMS]	~~81 ppmvd @ 7% O_2, 30-day rolling average (normal operation)~~ ~~162 ppmvd @ 7% O_2, 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 ~~(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 ~~(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. 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 operationg 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.

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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
G. Koerner
C. Holladay
A. Blackburn, SD
D. Worley, EPA
J. 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 <u>Public Notice</u> 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 <u>Public Notice</u>

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

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