**Memorandum**

# Florida Department of Environmental Protection

TO: Joe Kahn, Division of Air Resource Management

THROUGH: Trina Vielhauer, Bureau of Air Regulation TV

FROM: Jeff Koerner, New Source Review Section

DATE: August 9, 2010

SUBJECT: Permit No. 0510003-032-AV
Final Title V Air Operation Permit Renewal
United States Sugar Corporation
Clewiston Sugar Mill and Refinery

This project renews the Title V air operation permit for the existing facility and incorporates new requirements from recently issued air construction permits. As described in the attached Final Determination, only minor changes were made to the draft/proposed permit based on comments from the applicant. I recommend your approval of the attached final permit package.

Attachments

TLV/jfk

# NOTICE OF FINAL PERMIT

*In the Matter of an*
*Application for Permit by:*

Mr. Neil Smith, Vice President and General Manager
Sugar Processing Operations
United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, FL 33440

Permit No. 0510003-032-AV
Title V Air Operation Permit Renewal
Clewiston Sugar Mill and Refinery
ARMS ID No. 0510003
Hendry County, Florida

Enclosed is the final permit package to renew the Title V air operation permit for the existing Clewiston Sugar Mill and Refinery, which is located in Hendry County at the intersection of W.C. Owens Avenue and State Road 832 in Clewiston, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/jfk

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit and Final Determination), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Neil Smith, U.S. Sugar (nsmith@ussugar.com)
Mr. Keith Tingberg, U.S. Sugar (ktingberg@ussugar.com)
Mr. David Buff, Golder Associates (dbuff@golder.com)
Mr. Ajaya Satyal, DEP South District Office (ajaya.satyal@dep.state.fl.us)
Ms. Kathleen Forney, EPA Region 4 (forney.kathleen@epa.gov)
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Ms. Ana M. Oquendo, EPA Region 4 (oquendo.ana@epa.gov)
Ms. Barbara Friday, DEP BAR for posting with U.S. EPA Region 4 (barbara.friday@dep.state.fl.us)
Ms. Victoria Gibson, DEP BAR for Reading File (victoria.gibson@dep.state.fl.us)

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.

Barbara J. Friday (Clerk) 8/20/10 (Date)

## PERMITTEE

United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, FL 33440

## PERMITTING AUTHORITY

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

## PROJECT

Permit No. 0510003-032-AV
United States Sugar Corporation
Clewiston Sugar Mill and Refinery

The purpose of this project is to revise and renew the Title V air operation permit for the above referenced facility.

## NOTICE AND PUBLICATION

The Department distributed a draft/proposed permit package on February 8, 2010. The applicant published the Public Notice of intent to issue a Title V air operation permit in both The Glades County Democrat and The Clewiston News on July 1, 2010. The Department received the proof of publication on August 2, 2010.

## COMMENTS

No comments on the draft/proposed permit were received from the EPA Region 4 Office or the public. The applicant submitted the following comments requesting corrections and clarifications.

### Subsection 3A. Boilers 1 and 2

*Condition A.3.a.* In the second sentence, delete the extraneous apostrophe (') between the words "or" and "during". Response: The correction was made.

### Subsection 3C. Boiler 7

*Condition C.28.* This condition requires quarterly reporting for distillate oil and cites Permit No. 0510003-018-AC and NSPS Subpart Db as the underlying requirements. Revise to semiannual reporting consistent with the revised requirement in 40 CFR 60.49b(w). *Response*: Permit No. 0510003-018-AC does not require quarterly reporting for distillate oil and this citation will be removed. Original Permit No. PSD-FL-208 (AC26-238006) required quarterly reporting pursuant to 40 CFR 60.49b, which now allows semiannual reporting. The condition was corrected as follows:

> "~~Quarterly~~ Semiannual Report - Oil Firing: Within 30 days following each semiannual period (January to June and July to December) ~~calendar quarter~~, the permittee shall submit to the Compliance Authority: the distillate oil consumption for each month and the 12-month rolling total (gallons); and the certified vendor fuel analysis for each delivery of distillate oil during the reporting period ~~quarter~~. [~~Permit No. 0510003-018-AC and~~ 40 CFR 60.49b(w)~~, Subpart Db~~]"

### Subsection 3D. Boiler 8

*Condition D.24.* This condition requires quarterly reporting for distillate oil and cites an outdated alternate sampling procedure (ASP No. 95-B-1). Revise quarterly reporting to semiannual reporting consistent with 40

CFR 60.49b(w). *Response*: Condition 19e in Permit No. PSD-FL-333C (0510003-018-AC) required quarter reporting for distillate oil as part of the original alternative opacity monitoring plan approved by EPA on September 22, 2003. However, that plan was superseded by a subsequent alternative opacity monitoring plan approved by EPA on May 13, 2008, which did not require quarterly reporting for distillate oil. The condition will be corrected as follows and made consistent with the NSPS reporting requirement:

> ~~Quarterly~~ Semiannual Report - Oil Firing: Within 30 days following each semiannual period (January to June and July to December) ~~calendar quarter~~, the permittee shall submit to the Compliance Authority: the distillate oil consumption for each month and the 12-month rolling total (gallons); the certified vendor fuel analysis for each delivery of distillate oil during the reporting period ~~quarter; and a copy of the visible emissions observation log for oil firing during the calendar quarter~~. [~~ASP No. 95-B-01~~ 40 CFR 60.49b(w)]

**Section 4. Appendix I. Fuel Monitoring**

**Page I-1.**

*Condition 5a*: The applicant requests that the heating value of the fuel be included with the certified fuel oil analysis from the vendor. Since this requires specialty analysis, not normally supplied with the standard vendor analysis, it is requested that this requirement be removed. The heating value must already meet minimum American Society for Testing and Materials (ASTM) specifications for distillate fuel oil. *Response*: Condition 5a states:

> "For each oil delivery, the permittee shall maintain records of: the date, the gallons delivered, and a certified fuel oil analysis from the vendor including the heating value (Btu/lb), density (pounds/gallon) and sulfur content (percent by weight)."

This is consistent with the underlying requirements from Permit Nos. 0510003-018-AC, 0510003-029-Ac and 0510003-039-AC. No change was made.

*Condition 5b*: The applicant requests that the methods required by the Mandatory Greenhouse Gas Reporting Rule (40 CFR 98) be added to the list of allowable test methods. *Response*: This permit does not address greenhouse gas emissions. In the preamble to the final rule, EPA responded to comments that the greenhouse gas reporting rule is not considered an applicable requirement under the Title V operating permit program (56288 Federal Register; Volume 74; No. 209; Friday, October 30, 2009; Rules and Regulations). No change was made.

**CONCLUSION**

The final action of the Department is to issue the permit with the corrections and clarifications identified above.

**Title V Air Operation Permit Renewal**
**Permit No. 0510003-032-AV**
**United States Sugar Corporation**
**Clewiston Sugar Mill and Refinery**

## APPLICANT

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

## FACILITY DESCRIPTION

The U.S. Sugar Corporation operates a sugar mill (SIC No. 2061) and sugar refinery (SIC No. 2062) in Hendry County located at the intersection of W.C. Owens Avenue and State Road 832 in Clewiston, Florida. The UTM map coordinates are Zone 17, 506.1 E, and 2956.9 N. Sugarcane is harvested from nearby fields and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery.

The existing facility:

- Is a Title V major source of air pollution in accordance with Chapter 62-213, Florida Administrative Code (F.A.C.);
- Is a major stationary source of air pollution in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality;
- Is a major source of hazardous air pollutants; and
- Operates units subject to the New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions), Subpart Db (Industrial-Commercial-Institutional Boilers) and Subpart Dc (Small Industrial-Commercial-Institutional Boilers).

This permit includes the following regulated emissions units.

| **ARMS Facility ID No. 0510003** | |
|---|---|
| **EU No.** | **Emissions Unit Description** |
| *Sugar Mill* | |
| 001 | Boiler 1 |
| 002 | Boiler 2 |
| 009 | Boiler 4 |
| 014 | Boiler 7 |
| 027 | Biomass Handling and Storage |
| 028 | Boiler 8 |
| 031 | Lime Storage and Truck/Rail Handling System |
| *Sugar Refinery* | |
| 015 | VHP Sugar Dryer |
| 016 | White Sugar Dryer No. 1 |
| 017 | Granular Carbon Regeneration Furnace |
| 018 | Vacuum Pickup Systems |

| ARMS Facility ID No. 0510003 | |
|---|---|
| **EU No.** | **Emissions Unit Description** |
| 019 | Conditioning Silos |
| 020 | Screening/Distribution and Sugar/Starch Bins |
| 021 | Alcohol Usage |
| 022 | Packaging Dust Collector |
| 029 | White Sugar Dryer No. 2 |
| 035 | Rental Refinery Package Boiler |
| *Facility* | |
| 010 | Lime Silo with Baghouse at the Water Treatment Plant |
| 030 | Limestone Storage Silo with Baghouse at the Molasses Plant |
| 033 | Salt Silo with Baghouse at the Molasses Plant |

The Title V permit also identifies unregulated and shutdown emissions units (Appendix D) and insignificant emissions units (Appendix E).

## PROJECT DESCRIPTION

On June 2, 2005, the Department received a single application to renew the Title V permits for the Clewiston sugar mill in Hendry County and the Bryant sugar mill in Palm Beach County. Processing of the Title V application was delayed for several reasons including: a request to consider the Clewiston and Bryant facilities as a single facility based on issues such as common control, adjacency, etc.; several revisions requested to incorporate numerous air construction permits processed since the last issuance and during the processing period; a request to incorporate the applicable National Emissions Standards for Hazardous Air Pollutants (NESHAP) in Subpart DDDDD of 40 CFR 63; a revision requested for a health-based compliance alternative to the NESHAP DDDDD provisions for existing boilers; and requests to modify Permit No. PSD-FL-333 for newly constructed Boiler 8. During the processing, U.S. Sugar decided to permanently shut down the Bryant sugar mill and sell the existing equipment. The Title V permit for the Bryant sugar mill was expired by the Department on September 28, 2007. Also during processing, the court vacated NESHAP DDDDD and it is no longer applicable. Once these issues were resolved, permit processing went forward. The following summarizes the current requests.

- Includes a Compliance Assurance Monitoring (CAM) plan for each affected unit.
- Updates unregulated emissions units, insignificant activities and permanently shutdown emissions units.
- Clarifies the applicability of NSPS Subpart Kb for the distillate oil storage tanks.
- Incorporates Permit No. 0510003-022-AC, which authorized specific off season repairs for Boilers 1, 2, 3, 4 and 7. All of the work has been completed and is now obsolete. Only the record keeping and reporting requirements for off season maintenance is included in Appendix J.
- Incorporates Permit No. 0510003-025-AC, which authorized the construction of a salt silo with baghouse at the molasses plant.
- Incorporates Permit No. 0510003-029-AC, which authorized oil burner modifications to Boilers 4 and 7. The oil firing conditions for Boiler 4 were later revised in Permit No. 0510003-039-AC along with Boilers 1 and 2. See below.
- Incorporates Permit No. 0510003-031-AC, which makes miscellaneous revisions to several permits and is being processed concurrently with the Title V renewal. See the Technical Evaluation and Preliminary Determination for a full discussion of the revisions.
- Incorporates Permit No. 0510003-033-AC, which authorized the construction of a limestone silo with baghouse.

- Incorporates Permit No. 0510003-034-AC, which authorized the construction of a new lime storage and truck/rail handling system with baghouse controls.
- Incorporates Permit No. 0510003-037-AC (PSD-FL-333C), which authorized construction of Boiler 8 and modification of the biomass handling system.
- Incorporates Permit No. 0510003-038-AC (PSD-FL-346A), which authorized construction of white sugar dryer No. 2.
- Incorporates Permit No. 0510003-039-AC, which authorized modifications to the oil firing systems for Boilers 1, 2 and 4. It supersedes Permit Nos. 0510003-027-AC and 0510003-036-AC for Boilers 1 and 2 as well as Permit Nos. 0510003-018-AC and 0510003-029-AC for Boiler 4.
- Incorporates Permit No. 0510003-045-AC, which authorizes the addition of a rental package boiler.
- Incorporates Permit No. 0510003-044-AC (PSD-FL-389), which adds wood chips to Boiler 7.

It is noted that several other air construction permitting actions issued within this time frame were not incorporated for a variety of reasons, including: replacement by a subsequent permit; shutdown of the emissions unit; and temporary authorizations such as a trial burn.

On February 8, 2008, the Department issued an initial draft permit package. The applicant filed an extension of time in which to file a petition and submitted numerous comments primarily on the CAM plan. A public notice was never published. On October 26, 2009, the applicant submitted a revision to the application that requested additional changes and provided additional test and monitoring data for the CAM plan. On January 14, 2010, the Department received a revised application to include the alternative flue gas moisture monitoring method for Boiler No. 8. A revised draft/proposed permit package was issued on February 8, 2010.

## APPLICABLE REQUIREMENTS

### Applicable State Regulations

The environmental laws specified in Section 403 of the Florida Statutes (F.S.) authorize the Department of Environmental Protection (Department) to establish rules and regulations regarding air quality as part of the F.A.C. Emissions units at this facility are subject to the applicable requirements defined in the following F.A.C. Chapters: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and Best Available Control Technology, and Non-attainment Area Review and Lowest Achievable Emission Rate; 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). Emissions units are subject to the following source-specific regulations.

- Boilers 1, 2, 4, 7 and 8 (EU-001, 002, 009, 014 and 028) are subject to Rule 62-296.410, F.A.C. for carbonaceous fuel burning equipment.
- Boilers 4, 7 and 8 (EU-009, 014 and 028), the biomass handling and storage (EU-027) and emissions units in the sugar refinery (EU-015, 016, 017, 018, 019, 020, 021, 022 and 029) are subject to Rule 62-212.400(BACT), F.A.C.
- For all emissions units requiring tests, Rule 62-297.310, F.A.C. establishes the general requirements.
- The following emissions units are subject to the applicable provisions in Rule 62-213.440, F.A.C. for Compliance Assurance Monitoring: Boilers 1, 2, 4, 7 and 8 (EU-001, 002, 009, 014 and 028), granular carbon regeneration furnace (EU-017), three vacuum pickup systems (EU-018) and white sugar dryer 2 (EU-029).

### Applicable Federal Regulations

Federal environmental requirements are established in Title 40 of the Code of Federal Regulations (CFR). Emissions units are subject to the following source-specific regulations.

- Boilers 7 (EU-014) and 8 (EU-028) are subject to the New Source Performance Standards (NSPS) in Subpart Db of 40 CFR 60 for Industrial-Commercial-Institutional Steam Generating Units.
- The rental package boiler (EU-035) may be subject to NSPS Subpart Dc when added.
- All sources subject to a specific NSPS subpart are also subject to the applicable General Provisions in NSPS Subpart A of 40 CFR 60.

## COMPLIANCE ASSURANCE MONITORING (CAM) PLANS

Table A summarizes CAM applicability for each existing emissions unit. The CAM provisions do not apply to: units without a control device; smaller units with uncontrolled emissions less than the major source thresholds; units without an emissions limiting standard that are restricted only by fuel consumption, process rates and/or production limits; units in which the control device is an integral part of the process and that could not be operated without the control device in place; and units for which compliance is demonstrated with an emissions standard by a continuous emissions monitoring system (CEMS). As shown in Table A on the following page, CAM Plans are required for particulate matter control devices for the following affected units.

- Wet impingement scrubber for Boilers 1, 2 and 4 (EU-001, 002 and 009);
- Electrostatic precipitators (ESP) for Boilers 7 and 8 (EU-014 and 028);
- Wet scrubber system for granular carbon regeneration furnace (EU-017);
- Baghouse controls for three vacuum pickup systems (EU-018); and
- Wet scrubber system for white sugar dryer 2 (EU-029).

This section identifies the CAM indicators and excursion levels for the affected units.

### Wet Impingement Scrubbers for Boilers 1, 2 and 4 (EU-001, 002 and 009)

Particulate matter emissions from these boilers are controlled by Joy Turbulaire wet impingement scrubbers. Particles are removed by water impaction through a series of spray nozzles in the scrubber body and by changing the gas direction at the bottom of the scrubber just above the liquid level. Monitoring the pressure drop across the wet scrubber provides a measure of the energy imparted to the gas stream. Monitoring the total scrubber water flow rate ensures there is sufficient water available for impaction and effective control. The plant currently monitors both of these parameters. Based on past tests, the following table summarizes the applicant's request and the Department's selected excursion levels for these parameters.

| Boiler | Pressure Drop, Inches of Water Column | | Flow Rate, gpm | |
|---|---|---|---|---|
| | Requested | Selected | Requested | Selected |
| 1 | 6.3 | 6.5 | 191 | 200 |
| 2 | 5.4 | 5.5 | 200 | 200 |
| 4 | 5.8 | 6 | 220 | 220 |

Boilers 1 and 2 are both vibrating grate boilers (185,000 lb/hour of steam) with identical exhaust flow rates (250,000 acfm) and wet impingement scrubbers (Joy Turbulaire Type D, Size 125). Boiler 4 is a traveling grate boiler (271,604 lb/hour of steam) with an exhaust flow rate of 281,000 acfm controlled by a Type D, Size 200 Joy Turbulaire wet impingement scrubber. For Boiler 1, PM test data ranged from 0.118 to 0.248 lb/MMBtu with monitoring data ranging from 7 to 12 inches of water column (w.c.) and 212 to 370 gallons per minute (gpm). For Boiler 2, PM test data ranged from 0.093 to 0.229 lb/MMBtu with monitoring data ranging from 6 to 12 inches of w.c. and 222 to 354 gpm. For Boiler 4, PM test data ranged from 0.061 to 0.142 lb/MMBtu with monitoring data ranging from 6.4 to 22.5 inches w.c. and 245 to 623 gpm.

**Table A. CAM Applicability for Emissions Units with Control Devices**

| EU No. | Description | Control Device | Pollutant | Emissions Standard | CEMS? | Integral? | > Major? | CAM? |
|---|---|---|---|---|---|---|---|---|
| 001 | Boiler 1 | Wet Scrubber | PM | 0.25 lb/MMBtu, bagasse<br>0.10 lb/MMBtu, oil | No | No | Yes | **Yes** |
| 002 | Boiler 2 | Wet Scrubber | PM | 0.25 lb/MMBtu, bagasse<br>0.10 lb/MMBtu, oil | No | No | Yes | **Yes** |
| 009 | Boiler 4 | Wet Scrubber | PM | 0.15 lb/MMBtu, bagasse<br>0.10 lb/MMBtu, oil | No | No | Yes | **Yes** |
| 010 | Lime Silo for Water Treatment Plant | Baghouse | PM | Opacity Only | No | No | No | **No** |
| 011 | Lime Silo for Sugar Mill and Boiling House | Baghouse | PM | Opacity Only | No | No | No | **No** |
| 014 | Boiler 7 | Wet Cyclones/ESP | PM | 0.03 lb/MMBtu | No | No | Yes | **Yes** |
| 015 | VHP Sugar Dryer (S-11) | Baghouse | PM | 1.63 lb/hour | No | Yes | --- | **No** |
| 016 | White Sugar Dryer 1 (S-10) | Baghouse | PM | 1.44 lb/hour | No | Yes | --- | **No** |
| 017 | Granular Carbon Regeneration Furnace (S-12) | Wet Scrubber | PM | 0.7 lb/hour | No | No | Yes | **Yes** |
| | | Afterburner | VOC | 1.0 lb/hour | No | No | No | **No** |
| 018 | Three Vacuum Pickup Systems (S-1, S-2, S-3) | Baghouse | PM | 0.06 lb/hour, each | No | No | Yes | **Yes** |
| 019 | Three Conditioning Silos (S-7, S-8, S-9) | Baghouse | PM | 0.06 lb/hour, each | No | No | No | **No** |
| 020 | Screening/Distribution and Sugar/Starch Bins (S-5, S-6) | Baghouse | PM | 0.06 lb/hour<br>0.19 lb/hour | No | No | No | **No** |
| 022 | Packaging Dust Collector (S-4) | Baghouse | PM | 0.21 lb/hour | No | No | No | **No** |
| 027 | Biomass Handling and Storage | Enclosure | PM | --- | --- | --- | --- | **No** |
| 028 | Boiler 8 | Wet Cyclones/ESP | PM | 0.025 lb/MMBtu (BACT) | No | No | Yes | **Yes** |
| | | SNCR System | NOx | 0.14 lb/MMBtu | Yes | No | Yes | **No** |
| 029 | White Sugar Dryer 2 (S-13) | Wet Scrubber | PM | 0.005 grains per dscf | No | No | Yes | **Yes** |
| 030 | Limestone Silo | Baghouse | PM | Opacity Only | | | | **No** |
| 031 | Two Lime Silos for Truck/Rail Unloading | Baghouse | PM | Opacity Only | | | | **No** |

Notes:

ESP means electrostatic precipitator. SNCR means selective non-catalytic reduction. ACI means activated carbon injection.

For the wet impingement scrubbers, a review of the data shows no direct correlation with emissions versus scrubber pressure drop or flow rate. Instead, it suggests an acceptable wide operating range for the scrubber. The applicant based the excursion levels on 90% of the lowest monitored value. In this particular case, the Department accepts this methodology because of the corresponding PM emission levels at the minimum values as well as the lack of correlation between monitoring data and emission rates. The Department rounded the pressure drop excursion level up to the nearest 0.5 inches of water column, which is identified as the minimum accuracy for the equipment. In addition, the applicant recommended a monitoring frequency of once per 8-hour shift. Again, this is because the boilers typically operate at a relatively high and continuous load and there is no direct correlation between the wet scrubber parameters and the PM standard. Instead, the purpose of monitoring the wet scrubber parameters is to ensure that plant personnel are maintaining minimum normal operating conditions that indicate effective control. The Department established a monitoring frequency of once every four hours so that the operators will check the boilers at least twice per shift.

**Electrostatic Precipitators for Boilers 7 and 8 (EU-014 and 028)**

Boilers 7 and 8 control PM emissions with cyclones followed by ESP. The cyclones remove large ash particles before the induced draft fan and cannot be adjusted for performance. Therefore, For Boilers 7 and 8, the applicant provided PM test runs for which the ESP secondary power input was monitored. All tests demonstrated compliance with the PM standards. For Boiler 7, the ESP secondary power input ranged from 41.9 to 103.9 kilowatts (kW). For Boiler 8, the ESP secondary power input ranged from 28 to 101 kW for the crop season (permitted capacity) and 20.2 to 45.5 kW for the off-season (about 50% of permitted capacity). Based on past tests and monitoring data, the applicant recommended the following excursion levels for these parameters.

| Boiler | Total secondary power input, kW | |
|---|---|---|
| | Requested | Selected |
| 7 | 38 | 38 |
| 8 | 25 crop season | 25 crop season |
| | 18 off season | 18 off season |

Again, the applicant selected the excursion level as 90% of the lowest ESP secondary power input under which demonstrated compliance with the PM standard. In this particular case, the Department accepts this methodology because of the corresponding PM emission levels at the minimum values as well as the lack of correlation between monitoring data and emission rates. These parameters will be continuously monitored and the 3-hour block average recorded. This is consistent with the alternative opacity monitoring plans as approved by EPA Region 4 for Boiler 7 (letter dated February 1, 2008) and Boiler 8 (letter dated May 13, 2008).

**Wet Scrubber System for Granular Carbon Regeneration Furnace (EU-017)**

Particulate emissions from the granular carbon regenerative furnace are controlled by a wet scrubbing system consisting of a high-energy wet venturi scrubber followed by tray-type wet scrubber. Permit No. PSD-FL-272A identifies the following operating ranges for pressure drops across this equipment: 12 to 30 inches of water column for the venturi scrubber and 3 to 8 inches of water column across the tray-type scrubber. The pressure drops are measures of the energy imparted to the gas stream and efficiency of the scrubbing process. The following table summarizes the applicant's request and the Department's selection of the excursion levels.

| Venturi Wet Scrubber | | Tray-Type Wet Scrubber | |
|---|---|---|---|
| Pressure Drop, Inches of Water Column | | Pressure Drop, Inches of Water Column | |
| Requested | Selected | Requested | Selected |
| 20 | 20 | 4 | 6.5 |

The applicant recommended the minimum venturi pressure scrubber drop that showed compliance with the PM standard. However, the applicant recommended the minimum tray-type scrubber pressure drop that showed compliance with the opacity standard. The Department accepted the minimum venturi pressure scrubber drop, but selected a minimum tray-type scrubber pressure drop of 6.5 inches of water column, which represents the minimum level that showed compliance with the PM standard rounded up to the nearest 0.5 inches of water column.

The potential annual PM emissions rate based on control is 3.1 tons/year. Permit No. PSD-FL-272A currently requires an observation and recording of the scrubber pressure drops at least once per 8-hour shift. The Department believes this is sufficient to ensure proper operation and functioning of the wet scrubber control system and establishes this frequency in the CAM plan.

**Baghouse Controls for Three Vacuum Pickup Systems (EU-018)**

The three vacuum systems collect dust from the screening/distribution bins and packaging operations controlled by three baghouses. Potential uncontrolled PM emissions from each baghouse are greater than 100 tons/year. Assuming continuous operation throughout the year (8760 hours per year), potential controlled emissions from each baghouse are 0.8 tons per year. Since the applicant indicates that these systems are not considered integral processing equipment, CAM applies. For each baghouse exhaust, the applicant requests a daily visible emissions check. The observation would be in accordance with EPA Method 22 for one minute. This method does not require a trained observer, but just a determination of the presence of visible emissions. If visible emissions are observed corrective actions shall be taken in accordance with the CAM provisions. For these small sources, the Department agrees that this monitoring method is sufficient.

**Wet Scrubber System for White Sugar Dryer 2 (EU-029)**

For white sugar dryer 2, PM emissions consist of refined sugar. A series of cyclone collectors remove the bulk of the dry sugar, which is transferred to the conditioning silos. The cyclones are considered integral processing equipment and are not subject to CAM. Residual PM emissions are removed by a wet scrubber system, which is subject to CAM. The wet scrubber is a Centrifield Vortex Model 150 manufactured by Entoleter, LLC. The pressure drop is a measure of the energy imparted to the gas stream and efficiency of the scrubbing process. An adequate water recirculation rate is necessary for proper operation of the system. Based on the manufacturer's specifications, Permit No. PSD-FL-346A (Project No. 0510003-038-AC) established a minimum pressure drop of 8 inches of water column and a minimum scrubber water recirculation rate of 500 gpm based on 3-hour block averages. Past PM emissions tests indicate compliance at these minimum levels. As requested by the applicant, the Department selects these minimum scrubber parameters as excursion levels for the CAM plan.

**Discussion of $SO_2$ "Controls" for Boilers 4, 7 and 8 (EU-009, 014 and 028)**

Boilers 4, 7 and 8 have the following $SO_2$ emissions standards for firing bagasse: Boiler 4 (0.06 lb/MMBtu); Boiler 7 (0.17 lb/MMBtu); and Boiler 8 (0.06 lb/MMBtu). Boiler 4 employs a wet impingement scrubber and Boilers 7 and 8 employ wet cyclones. Although these control devices were not specifically designed or installed to control $SO_2$ emissions, some reductions are likely being achieved. It is not clear that these wet controls are necessary for compliance.

According to the sugar industry, much of the $SO_2$ generated from combusting bagasse is adsorbed onto fly ash particles created during combustion. These particles are then removed by the particulate matter control device. To evaluate this removal mechanism, data was reviewed from the New Hope Power cogeneration boilers at the Okeelanta sugar mill. These units are spreader-stoker boilers similar in size to the larger Clewiston boilers (760 MMBtu per hour) that fire roughly a 50% / 50% blend of bagasse and wood chips as the primary fuel. However, no water is used in the particulate control device. Instead, particulate matter is removed with dry multi-clones followed by a dry electrostatic precipitator (ESP). For the Okeelanta Mill, the typical parameters are:

- Bagasse: 3600 Btu/lb (as fired), 52% moisture and a sulfur content of 0.03% by weight
- Wood Chips: 4500 Btu/lb (as fired), 37% moisture and an average sulfur content of 0.07% by weight

A 50% / 50% biomass blend by weight provides a fuel blend with an average heating value of 7322MBtu/lb (dry) and an average sulfur content of 0.05% sulfur by weight. This is equivalent to an uncontrolled emission rate of approximately 0.14 lb $SO_2$ per MMBtu. However, the cogeneration boilers are equipped with continuous emissions monitor systems (CEMS) to measure and record $SO_2$ emissions. Based on CEMS data collected in 2000 for the cogeneration boilers, the average annual $SO_2$ emission rate for these units was approximately 0.03

lb/MMBtu. This represents an estimated reduction of approximately 79%, which seems to validate that the $SO_2$ removal mechanism as being adsorption onto fly ash with removal by the particulate matter control device.

Representative data for the existing Clewiston Boiler 8 indicates bagasse with the following average values: a heating value of 3600 Btu/lb (wet), a moisture content of 52% and a sulfur content of 0.08% by weight (high value). The resulting uncontrolled emissions factor would be 0.21 lb/MMBtu. Assuming a 79% reduction based on fly ash adsorption and removal in the particulate control, the $SO_2$ emissions rate would be 0.04 lb/MMBtu. This is supported by the following averages based on stack test data: Boiler 4 (0.002 lb/MMBtu); Boiler 7 (0.03 lb/MMBtu); and Boiler 8 (0.02 lb/MMBtu). This shows that it is likely the $SO_2$ emissions limits will be met with a specific control for $SO_2$ emissions. The evaluation supports the applicant's contention that it is not the "wet" scrubbing action, but rather adsorption and removal with a particulate control device. Since a CAM plan has been established for the particulate control equipment, no additional CAM provisions are necessary.

## CLARIFICATIONS, CORRECTIONS AND UPDATES

### Distillate Oil Tanks for Boilers (EU-024, 025 and 026)

The following emissions units have previously been identified with an emissions unit ID and were believed to be subject to the provisions for fuel tanks in NSPS Subpart Kb of 40 CFR 60.

| EU No. | Emission Unit Description |
|---|---|
| 024 | Fuel tank with a capacity of 100,000 gallons |
| 025 | Fuel tank with a capacity of 400,000 gallons |
| 026 | Fuel tank with a capacity of 200,000 gallons |

On October 15, 2003, several clarifications were made to NSPS Subpart Kb including 40 CFR 60.110b (b):

> "This subpart *does not apply* to storage vessels with a capacity greater than or equal to $151 m^3$ storing a liquid with a maximum true vapor pressure *less than 3.5 kilopascals (0.51 psia)* or with a capacity greater than *or* equal to 75 $m^3$ but less than 151 $m^3$ storing a liquid with a maximum true vapor pressure *less than 15.0 kPa (2.17 psia).*"

Vapor pressure is the pressure of a confined vapor in equilibrium with a stored liquid at a given temperature. It is a measure of the volatility of the stored liquid. In general, NSPS Subpart Kb is intended to regulate liquids much more volatile than fuel oil, such as gasoline. Distillate oil has a vapor pressure of approximately 0.009 pounds per square inch, absolute (psia) at 70° F, which is well below either of the vapor pressures specified above and shows that such oil is not considered to be very volatile. Therefore, NSPS Subpart Kb does not apply to any tanks at the facility storing distillate oil, including the above tanks. Any references to the Subpart Kb requirements for distillate oil will be removed from the Title V permit. The above emissions units will be deactivated in the ARMS database and moved to Appendix D for unregulated emissions units.

### Permit Condition for Combined Plumes, Boilers 1, 2 and 4 (EU-001, 002 and 009)

Because of the location of Boilers 1, 2 and 4, the plumes from these stacks are often combined; this makes it difficult to distinguish the opacity attributed to each boiler. Since compliance tests are often scheduled weeks or months in advance, the following permit condition will allow an alternate method to be used in lieu of conducting the scheduled annual visible emissions compliance test.

> "<u>Combined Plumes, Alternate Method for Stack Opacity</u>: It is possible that combined plumes from adjacent boilers will prevent a reliable determination of compliance with the opacity standard. If the permittee is unable to perform the scheduled annual visible emissions test because of combined plumes, the permittee shall record the scrubber pressure drop and inlet water pressure during each test run for particulate matter at 15-minute intervals. The test report shall note the attempt to perform the annual visible emissions test, the reason for not being able to complete the test and shall identify scrubber pressure drops recorded during each test run for particulate matter. [Rules 62-4.070(3), 62-213.440(1)(b) and 62-297.310(7)(a)4, F.A.C.]"

This condition will be included for Boilers 1, 2 and 4.

**Permit No. PSD-FL-208, Equivalent Wet Bagasse Consumption Rates for Boiler 7 (EU-014)**

Condition 7 in Permit No. PSD-FL-208 specifies the following wet bagasse consumption rates for the corresponding heat input rates.

- 1-hour maximum: 203,060 lb/hour (101.5 tons/hour) of wet bagasse produces 812 MMBtu/hour; and
- 24-hour maximum: 184,600 lb/hour (92.3 tons/hour) of wet bagasse produces 738 MMBtu/hour

This would mean the heating value of bagasse is 3998 Btu/lb. However, permits for other boilers and the application identify the typical heating value of bagasse as 3600 Btu/lb. For consistency, the wet bagasse consumption rates for Boiler 7 will be specified in the permit as 113 and 103 tons/hour, which are the equivalent rates based on a typical heating value of bagasse as 3600 Btu/lb. In addition, Appendix I requires periodic sampling and analysis of the bagasse for the heating value.

**Permit No. PSD-FL-208, Emissions Limits for Oil Firing for Boiler 7 (EU-014)**

Permit No. 0510003-029-AC reestablished the oil firing conditions for Boiler 7. The only emissions standards specified for firing distillate oil were for $NO_X$, PM and opacity. For $NO_X$, the permit only required an initial test to verify the equipment design. No periodic tests were specified. The PM and opacity standards are the same for firing oil as for firing bagasse. No other emissions standards apply for oil firing.

## FINAL CONCLUSION

Based on reasonable assurances provided by the applicant, the Department issues this Title V permit under the provisions of Chapter 403, F.S. and Chapters 62-4, 62-204, 62-210, 62-296, 62-297 and 62-213, F.A.C. The permit authorizes operation of the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

**TITLE V AIR OPERATION PERMIT RENEWAL**

Permit No. 0510003-032-AV
(Renewal of Title V Air Operation Permit No. 0510003-017-AV)

United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, FL 33440

Facility ID No. 0510003
Hendry County, Florida

**Permitting Authority**

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

Telephone: 850/488-0114
Fax: 850/921-9533

**Compliance Authority**

State of Florida
Department of Environmental Protection
Air Resource Section
South District Office
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33902-2549

Telephone: 239/332-6975
Facsimile: 239/332-6969

*{Permitting Note: Appendix A contains a glossary of commonly used abbreviations and acronyms.}*

# Florida Department of Environmental Protection

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

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary


## TITLE V AIR OPERATION PERMIT

**PERMITTEE**

United States Sugar Corporation
111 Ponce de Leon Avenue
Clewiston, FL 33440

Permit No. 0510003-032-AV
Title V Permit Renewal
Clewiston Sugar Mill and Refinery
ARMS ID No. 0510003
Hendry County, Florida

Responsible Official:
Mr. Neil Smith, Vice President and General Manager
Sugar Processing Operations

The Department of Environmental Protection (Department) hereby renews the Title V air operation permit and authorizes continued operation of 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. The UTM map coordinates are Zone 17, 506.1 E, and 2956.9 N.

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

Effective Date: August 17, 2010
Renewal Application Due Date: January 3, 2015
Expiration Date: August 16, 2015

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/jfk

## FACILITY DESCRIPTION

U.S. Sugar operates a sugar mill and refinery in Hendry County located at the intersection of W.C. Owens Avenue and State Road 832 in Clewiston, Florida. The UTM map coordinates are Zone 17, 506.1 East and 2956.9 North. Sugarcane is harvested from adjacent, neighboring and remote fields in Glades, Hendry, Martin and Palm Beach counties and transported to the mill by train. In the mill, sugarcane is cut into small pieces and processed in a series of presses to squeeze juice from the cane. The juice undergoes clarification, separation, evaporation, and crystallization to produce raw, unrefined sugar. In the refinery, raw sugar is decolorized, concentrated, crystallized, dried, conditioned, screened, packaged, stored, and distributed as refined sugar. The fibrous byproduct remaining from the sugarcane is called bagasse and is burned as boiler fuel to provide steam and heating requirements for the mill and refinery. Molasses is also produced as a byproduct. Molasses is stored and processed into an animal feed product for sale.

## REGULATORY CATEGORIES

- The existing facility is a major source of hazardous air pollutants.
- The existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The existing facility is a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.
- Existing units are subject to the following New Source Performance Standards (NSPS) in Part 60 of Title 40, the Code of Federal Regulations (CFR): Subpart A (General Provisions), Subpart Db (Industrial-Commercial-Institutional Steam Generating Units) and Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units).
- No units are subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 63. *{Permitting Note: Initially, the boilers were subject to Subpart DDDDD (Industrial Boilers); however, this regulation was vacated and remanded to EPA for reconsideration.}*

## REGULATED POLLUTANTS

### Criteria Pollutants

Emissions units at this facility may emit one or more of the following criteria air pollutants: carbon monoxide (CO), nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less ($PM_{10}$), particulate matter with a mean particle diameter of 2.5 microns or less ($PM_{2.5}$), volatile organic compounds (VOC) and lead (Pb).

### Other Regulated PSD Pollutants

In addition to the above criteria air pollutants, emissions units at this facility may emit one or more of the following PSD pollutants: fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide ($H_2S$); total reduced sulfur (TRS), including $H_2S$; reduced sulfur compounds, including $H_2S$; and mercury (Hg).

### Hazardous Air Pollutants

Emissions units at this facility may emit one or more hazardous air pollutants (HAP) as defined in Rule 62-210.200, F.A.C.

## SUMMARY OF REGULATED EMISSIONS UNITS

| ARMS Facility ID No. 0510003 | |
|---|---|
| **EU No.** | **Emissions Unit Description** |
| *Sugar Mill* | |
| 001 | Boiler 1 |
| 002 | Boiler 2 |
| 009 | Boiler 4 |
| 014 | Boiler 7 |
| 027 | Biomass Handling and Storage |
| 028 | Boiler 8 |
| 031 | Lime Storage and Truck/Rail Handling System |
| *Sugar Refinery* | |
| 015 | VHP Sugar Dryer |
| 016 | White Sugar Dryer No. 1 |
| 017 | Granular Carbon Regeneration Furnace |
| 018 | Vacuum Pickup Systems |
| 019 | Conditioning Silos |
| 020 | Screening/Distribution and Sugar/Starch Bins |
| 021 | Alcohol Usage |
| 022 | Packaging Dust Collector |
| 029 | White Sugar Dryer No. 2 |
| 035 | Rental Refinery Package Boiler |
| *Facility* | |
| 010 | Lime Silo with Baghouse at the Water Treatment Plant |
| 030 | Limestone Storage Silo with Baghouse at the Molasses Plant |
| 033 | Salt Silo with Baghouse at the Molasses Plant |

*{Permitting Note: For the above facility, the following emissions units have been permanently shutdown and dismantled: Boiler 3 (EU-003); Boiler 5 (EU-004); Boiler 6 (EU-005); Lime Silo with Baghouse at the Boiling House (EU-011); Diesel Generators 1 (EU-012) and 2 (EU-013); Propane Sock Heaters (EU-023); and Portable Rock Crusher (EU-032).}*

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

## PERMITTING AND COMPLIANCE AUTHORITIES

1. Permitting Authority: The Department's Bureau of Air Regulation is the permitting authority for this renewal permit. The permitting authority for subsequent revisions and renewals is the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/332-6975 and the fax number is 239/332-6969.

2. Compliance Authority: The permittee shall submit all compliance related notifications and reports required of this permit to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/332-6975 and the fax number is 239/332-6969.

## PERMIT APPENDICES

3. Appendices: The appendices identified as Section 4 in the Table of Contents are attached as an enforceable part of this permit unless otherwise indicated.

## ANNUAL REPORTS AND FEES

4. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility in accordance with the requirements in Rule 62-210.370, F.A.C. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(3), F.A.C.]

5. Annual Emissions Fee: The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rule 62-213.205, F.A.C.]

## EMISSIONS AND CONTROLS

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. General VOC and OS Emission Limiting Standards: The permittee shall not store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. Nothing was deemed necessary and ordered on a facility-wide basis. [Rule 62-296.320(1)(a), F.A.C.]

8. General Visible Emissions: Unless otherwise specified by this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. If the presence of uncombined water is the only reason for failure to meet visible emission standards given in this rule, such failure shall not be a violation of this rule. All visible emissions tests performed pursuant to this rule shall be conducted in accordance with EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C. This permit condition does not impose any periodic testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

9. 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) and 62-210.200(Definitions), F.A.C.; and Permit No. PSD-FL-333D]

10. Unconfined Particulate Emissions: This permit requires the use of fans, filters, pneumatic unloading/loading, ductwork, storage silos and other similar equipment to contain, capture, and/or control particulate matter related to the storage and handling of fuels, raw materials and products. The permittee shall also take the following reasonable precautions to prevent fugitive particulate matter emissions from any activity, including: vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling of fuels, raw materials or products.

    a. Where practicable, enclose or cover conveyor systems.
    b. Minimize drop distances of dry materials when handling.
    c. As necessary, provide wind breaks around material handling equipment.
    d. Where possible, confine abrasive blasting.
    e. Paving and maintenance of roads, parking areas and yards.
    f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
    g. As necessary, provide landscape and/or vegetation.
    h. As necessary, remove dust from roads, work areas, parking areas, and other paved areas under the control of the permittee to prevent fugitive dust emissions.
    i. As necessary, apply water or other dust suppressants to control emissions from unpaved roads, yards, and other activities such as road grading, land clearing, and the demolition of buildings.

    [Rules 62-4.070(3) and 62-296.320(4)(c), F.A.C.]

11. Definitions: Unless otherwise specified by permit, startup, shutdown and malfunction are defined as follows.

    a. *Startup*: Startup is defined as 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.
    b. *Shutdown*: Shutdown is defined as the cessation of the operation of an emissions unit for any purpose.
    c. *Malfunction*: A malfunction is defined as 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(Definitions), F.A.C.]

12. 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 that are based on data collected from continuous emissions monitoring systems (CEMS). [Rule 62-210.700(4), F.A.C.]

13. Excess Emissions Allowed: Unless otherwise specified in an emissions unit subsection or Appendices of this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing:

    a. Best operational practices to minimize emissions are adhered to, and
    b. The duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period.

    Rule 62-210.700, F.A.C., cannot vary any federal NSPS or NESHAP provisions. [Rule 62-210.700(1), F.A.C.]

14. Excess Emissions Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. (Plant Operation - Problems). If requested, a full written report on the malfunctions shall be submitted in a quarterly report. [Rule 62-210.700(6), F.A.C.]

15. Plant Operation - Problems: 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. [Rule 62-4.130, F.A.C.]

**ADMINISTRATIVE REQUIREMENTS**

16. Renewal Application: The permittee shall submit an application to renew this permit using the appropriate form specified in Rule 62-210.900, F.A.C. prior to 225 days before the expiration of this permit. [Rules 62-4.090 and 62-213.420, F.A.C.]

17. Statement of Compliance: The permittee shall submit the annual statement of compliance using DEP Form No. 62-213.900(7), F.A.C. to the Compliance Authority and EPA within 60 days of the end of the calendar year. [Rules 62-213.440(3) and 62-213.900, F.A.C.]

18. 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 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

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

20. Reporting to EPA: Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency should be sent to: EPA Region 4 Office; Air, Pesticides & Toxics Management Division; Air and EPCRA Enforcement Branch - Air Enforcement Section; 61 Forsyth Street; Atlanta, Georgia 30303-8960. The telephone number is 404/562-9155 and the fax number is 404/562-9163.

21. Prevention of Accidental Releases (Section 112(r) of CAA):

    a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: 703/227-7650.

    b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.

    [40 CFR 68]

**Subsection A. Boilers 1 and 2**

This subsection addresses the following regulated emissions units.

| EU No. | Emissions Unit Description |
|---|---|
| 001 | Boiler 1 is a vibrating grate boiler with a maximum steam production rate of185,000 lb/hour (24-hour average) at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 125, Joy Turbulaire wet impingement scrubber. Exhaust gases exit at 150° F with an approximate flow rate of 250,000 acfm from a stack that is 8 feet in diameter and 213 feet tall. |
| 002 | Boiler 2 is a vibrating grate boiler with a maximum steam production rate of 185,000 lb/hour (24-hour average) at 750° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 125, Joy Turbulaire wet impingement scrubber. Exhaust gases exit at 150° F with an approximate flow rate of 250,000 acfm from a stack that is 8 feet in diameter and 213 feet tall. |

## CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS

A.1 Permitted Capacity: Boilers 1 and 2 are authorized to fire bagasse as the primary fuel and distillate oil as an auxiliary fuel. Each boiler shall not exceed the permitted capacities specified in the following table.

| Parameter | Boiler 1 | Boiler 2 |
|---|---|---|
| Steam Production, lb/hour (24-hour average) | 185,000 | 185,000 |
| Total Heat Input Rate, MMBtu/hour (24-hour average) | 397 | 397 |
| Heat Input Rate from Oil, MMBtu/hour (1-hour average) | 130 | 130 |
| Oil Firing Rate (gallons per hour, maximum) | 963 | 963 |

[Rules 62-4.070(3) and 62-213.440(4), F.A.C.; and Permit Nos. 0510003-039-AC and PSD-FL-272B]

A.2 Authorized Fuels: Each boiler is authorized to fire the following fuels.

a. *Bagasse*: The primary fuel is bagasse, which is the fibrous byproduct remaining from the sugarcane after milling.

b. *Distillate Oil*: Any oil fired in these boilers shall be new No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. The oil firing system for each boiler consists of the following general equipment: one multi-stage low-$NO_X$ burner (0.17 lb/MMBtu) with a steam-atomized center-fired oil gun; a flame scanner; an igniter with flame proving rod, and an individual burner wind box with an electrically-operated modulating damper.

c. *On-specification Used Oil*: Incidental amounts of on-specification used oil (≤0.05% sulfur by weight) generated on site may be co-fired.

d. *Petroleum-contaminated Soils*: Small quantities of petroleum-contaminated soils not to exceed 500 cubic yards per boiler per season may be co-fired. Such soils shall contain only soil, "virgin" fuels and oils, and/or "on-specification" used oil. Petroleum-contaminated soils shall be fired at a rate of no more than 2% by weight of the bagasse feed rate to the boiler.

Appendix I specifies the fuel monitoring requirements for fuels at this facility. [Rules 62-210.200(PTE), 62-212.400(12) and 62-213.410, F.A.C.; and Permit Nos. 0510003-039-AC and PSD-FL-272B]

A.3 Restricted Operation: These units operate primarily during the sugarcane crop season (October through April) and the hours of operation are not limited; however, the following restrictions apply.

a. *Off Season*: Boilers 7 and 8 shall operate as the primary units to support the sugar refinery during the off season (May through September). When Boilers 7 and 8 are down for maintenance, repair or during periods of unusually low steam demand, Boilers 1, 2 and 4 may operate individually or simultaneously as backup units, but the combined total steam production shall not exceed 1,845,000 pounds of steam during any 3-hour period and 10,800,000 pounds of steam during any 24-hour period. An application to modify any of the above steam production limitations shall be accompanied by a revised air quality analysis that demonstrates compliance with the ambient air quality standards and PSD increments for the revised conditions. A request to modify these restrictions shall be accompanied by a new PSD Air Quality Analysis.

b. *Oil Firing*: The combined oil firing from Boilers 1, 2 and 4 shall not exceed 6,000,000 gallons during any consecutive 12 months.

[Rule 62-210.200(PTE); and Permit Nos. PSD-FL-272B and 0510003-039-AC]

A.4 Startup, Shutdown and Malfunction Plans for Mill Boilers: Appendix K of this permit identifies the general procedures that will be used for startup, shutdown, and malfunction of the mill boilers including methods to minimize emissions. [Rules 62-4.070(3) and 62-210.700(1), F.A.C.]

## CONTROL EQUIPMENT AND TECHNIQUES

A.5 Wet Scrubbers: For each boiler, the permittee shall operate and maintain a Joy Turbulaire wet impingement scrubber (Type D, Size 125) to control particulate matter emissions and achieve the emissions standards specified in this permit. In accordance with the manufacturer's recommendations, each wet scrubber control system shall be equipped with instrumentation to monitor the total pressure drop across the scrubber (inches of water column) and water flow rate (gpm). Such instrumentation shall be calibrated at least annually, properly maintained and operational at all times, except during periods of breakdown, repair or calibration. Exhaust from the wet scrubber stacks shall be maintained at a minimum of 213 feet in height. The permittee shall operate the wet scrubber in accordance with the CAM provisions of this subsection as well as the general provisions in Appendix H of this permit. [Rules 62-4.070(3) and 62-213.440(4), F.A.C.; and Permit No. PSD-FL-272B]

A.6 Other Control Techniques: To minimize emissions of sulfur dioxide and sulfuric acid mist, the boilers shall only fire the authorized low-sulfur fuels specified in this subsection. As provided in Appendix J of this permit, operators shall follow the good combustion practices that are generally applicable to all sugar mill boilers. [Rules 62-4.070(3) and 62-210.200(PTE); and Permit No. PSD-FL-272B]

## EMISSION LIMITING STANDARDS

A.7 Opacity Standard: As determined by DEP Method 9, visible emissions from each boiler shall not exceed 30% opacity based on a six-minute average, except for one 2-minute period per hour that shall not exceed 40% opacity. This standard excludes water vapor and applies when firing any combination of authorized fuels. [Rule 62-296.410(1)(b)1, F.A.C.]

A.8 PM Standard: As determined by EPA Method 5, PM emissions shall not exceed 0.25 lb/MMBtu of heat input from firing bagasse plus 0.1 lb/MMBtu of heat input from firing oil. When burning a mixture of bagasse and oil, the emissions standard shall be prorated based on the portion of heat input provided from each fuel. A separate compliance test when firing only distillate oil is not required. [Rule 62-296.410(1)(b)2, F.A.C. Permit No. PSD-FL-208A]

## TESTING

A.9 General Testing Requirements: The boilers are subject to the applicable provisions in Appendix C of this permit, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

A.10 Test Methods: If required, stack tests shall be performed in accordance with the following methods or the most recent versions of these methods.

| EPA Method | Description of Method and Comments |
|---|---|
| 1 - 4 | Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content Methods shall be performed as necessary to support other methods. |
| 5 | Determination of PM Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity. The minimum observation period shall be no less than 60 minutes. |

The above 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 and 62-297.401, F.A.C.; and 40 CFR 60, Appendix A]

A.11 Annual Compliance Tests: During each federal fiscal year (October 1 - September 30), the permittee shall conduct compliance tests for particulate matter and visible emissions from each boiler. See Condition A.12 for an alternative to the visible emissions test when there are combined plumes. For each test run, the permittee shall record the following: steam production rate, temperature and pressure; feedwater flow rate, temperature and pressure; and, at 15 minute intervals, the scrubber pressure drop and water flow rate. For each particulate matter test run, the heat input rate shall be calculated from the steam production data and by assuming a 55% thermal efficiency for the boiler. [Rules 62-213.440(1)(b), 62-296.410(3), 62-297.310(4)(a)2 and 62-297.401, F.A.C.]

A.12 Combined Plumes, Alternate Method for Stack Opacity: It is possible that combined plumes from adjacent boilers will prevent a reliable determination of compliance with the opacity standard. If the permittee is unable to perform the scheduled annual visible emissions test because of combined plumes, the permittee shall record the scrubber pressure drop and water flow rate during each test run for particulate matter at 15-minute intervals. The test report shall note the attempt to perform the annual visible emissions test, the reason for not being able to complete the test and shall identify scrubber pressure drops and water flow rates recorded during each test run for particulate matter. [Rules 62-4.070(3), 62-213.440(1)(b) and 62-297.310(7)(a)4, F.A.C.]

## MONITORING, RECORD KEEPING AND REPORTING

A.13 Monitoring Equipment: In accordance with the manufacturer's recommendations, the permittee shall install, operate and maintain equipment to continuously monitor the following parameters: the steam production (lb/hour), pressure (psig) and temperature (° F); the feed water flow rate (gpm), pressure (psig) and temperature (° F); the scrubber flow rate (gpm) and pressure drop (inches of water column); and the total distillate oil fired (gallons). Each device shall be calibrated at least annually and calibration records maintained in a written or electronic log. [Rules 62-4.070(3) and 62-213.440(4), F.A.C.; and Permit Nos. PSD-FL-272B and 0510003-039-AC]

A.14 Daily Operational Records: To demonstrate compliance with the performance requirements of this permit, the permittee shall record the following information in daily logs.

a. *Boiler Operations*: The permittee shall record the time and date the boiler undergoes startup, shutdown, or malfunction. The permittee shall also log the time the boiler has achieved or regained normal operation. Chart recorders shall continuously record the steam pressure (psig), steam temperature (° F), and steam production rate (lb/hour).

b. *Wet Scrubber Parameters*: The wet scrubber shall be equipped with a manometer (or equivalent) to monitor the scrubber pressure drop (inches of water column) and a flow meter to monitor the scrubber water flow rate (gpm). The permittee shall comply with the applicable CAM Plan monitoring requirements in this subsection and Appendix H of this permit.

All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any. Automated recorders may be used to satisfy the monitoring requirements. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; and Permit No. 0510003-039-AC]

A.15 CAM Plan, Wet Scrubbers: The permittee shall comply with the following CAM plan for each boiler.

| CAM Criteria | Indicator #1 | Indicator #2 |
|---|---|---|
| Indicator | Pressure drop across scrubber | Total scrubber water flow rate |
| Measurement Approach | Manometer (or equivalent) | Flow meter |
| Indicator Range | An excursion is defined as any pressure drop **below 6.5 inches of water column for Boiler 1 and 5.5 inches of water column for Boiler 2**. Excursions trigger inspection, corrective action, record keeping and reporting. | An excursion is defined as any flow rate **below 200 gallons per minute for each boiler**. Excursions trigger inspection, corrective action, record keeping and reporting. |
| Data Representativeness | Manometer measures scrubber pressure drop with a minimum accuracy of ± 0.5 inches of water column (gage). | Flow meter measures scrubber flow rate with a minimum accuracy of ± 5% of total water flow. |
| Verification of Operational Status | NA | NA |
| QA/QC Procedures | Maintain equipment in accordance with manufacturer's recommendations. | Maintain equipment in accordance with manufacturer's recommendations. |
| Monitoring Frequency | Continuous readout | Continuous readout |
| Data Collection Procedures | Recorded at 4-hour intervals. | Recorded at 4-hour intervals. |
| Averaging Period | NA | NA |

In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. Automated recorders may be installed to satisfy the recording requirements. The permittee shall record any problems with operation of the wet scrubber and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; and 40 CFR 64]

A.16 Fuel Monitoring Provisions: The permittee shall comply with the applicable fuel monitoring requirements specified in Appendix I (Fuel Monitoring) for each authorized fuel. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; and Permit No. 0510003-039-AC]

A.17 Operating Records:

a. *Steam Production*: The permittee shall maintain records of the steam production suitable for review.

b. *Scrubber Parameters*: The permittee shall comply with the CAM plan specified in this subsection as well as the general provisions in Appendix H of this permit.

[Rules 62-4.070(3), 62-213.440(1)(b) and 62-213.440(1)(d)4, F.A.C.; and Permit Nos. PSD-FL-272B and 0510003-039-AC]

A.18 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

This subsection addresses the following regulated emissions unit.

| EU No. | Emissions Unit Description |
|---|---|
| 009 | Boiler 4 is a traveling grate boiler manufactured by Foster Wheeler with a maximum steam production rate of 271,604 lb/hour at 850° F and 600 psig. Bagasse is the primary fuel and distillate oil is a startup and supplemental fuel. Particulate matter emissions are controlled by a Type D, Size 200 Joy Turbulaire wet impingement scrubber. Exhaust gases exit a stack that is 150 feet tall and 8.2 feet in diameter at 160° F with an approximate flow rate of 281,000 acfm. |

## CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS

B.1 Permitted Capacity: Boiler 4 is authorized to fire bagasse as the primary fuel and distillate oil as an auxiliary fuel. Boiler 4 shall not exceed the permitted capacities specified in the following table.

| Averaging Period | Steam Pressure [a] | Steam Temperature [a] | Steam Production (lb/hour) | Heat Input [b] (MMBtu/hour) | Wet Bagasse Firing [b] (tons/hour) |
|---|---|---|---|---|---|
| 1-hour | 600 psig | 850° F | 286,543 | 633 | 88 |
| 24-hour | 600 psig | 850° F | 271,604 | 600 | 83 |

a. Steam temperature and pressure are design parameters. Prior to modifying the steam parameters, the permittee shall notify to the Department. Such changes may require a permit modification.

b. The maximum heat input and bagasse firing rates are estimated based on 55% thermal efficiency of the boiler; wet bagasse containing 55% moisture and a heat content of 3600 Btu/lb; and 1215 Btu (net) per pound of steam at 600 psig and 850° F with standard feed water conditions of 900 psig and 250° F.

c. The maximum heat input rate is 326 MMBtu per hour from firing a maximum of 2417 gallons per hour of distillate oil, which produces approximately 225,000 pounds of steam per hour from the sole firing of distillate oil.

The permittee shall maintain continuous monitoring records of the steam temperature, steam pressure, and steam production rate. [Rules 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; and Permit Nos. PSD-FL-272B and 0510003-039-AC]

B.2 Authorized Fuels: Boiler 4 is authorized to fire the following fuels.

a. *Bagasse*: The primary fuel is bagasse, which is the fibrous byproduct remaining from the sugarcane after milling.

b. *Distillate Oil*: Any oil fired in these boilers shall be new No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. The oil firing system consists of the following general equipment: two multi-stage low-$NO_X$ burners (~ 0.17 lb/MMBtu) with flame scanners; fuel/steam valve train; steam-atomized center-fired oil gun with igniter and flame proving rod; a multi-burner wind box; a fuel oil pump set; and a burner management control system.

c. *On-specification Used Oil*: Incidental amounts of on-specification used oil (≤0.05% sulfur by weight) generated on site may be co-fired.

[Rules 62-210.200(PTE) and 62-212.400(PSD); and Permit Nos. PSD-FL-272B and 0510003-039-AC]

B.3 Restricted Operation: Boiler 4 operates primarily during the sugarcane crop season (October through April) and the hours of operation are not limited; however, the following restrictions apply.

a. *Annual Heat Input Rate Limit*: In addition, the total heat input to this boiler shall not exceed 2,880,000 MMBtu during any consecutive 12 months (equivalent to approximately 400,000 tons of bagasse).

b. *Oil Firing*: The combined oil firing from Boilers 1, 2 and 4 shall not exceed 6,000,000 gallons during any consecutive 12 months.

c. *Off Season*: Boilers 7 and 8 shall operate as the primary units to support the sugar refinery during the off season (May through September). When Boilers 7 and 8 are down for maintenance, repair or during periods of unusually low steam demand, Boiler No's. 1, 2 and 4 may operate individually or simultaneously as backup units, but the combined total steam production shall not exceed 1,845,000 pounds of steam during any 3-hour period and 10,800,000 pounds of steam during any 24-hour period. An application to modify any of the above steam production limitations shall be accompanied by a revised air quality analysis that demonstrates compliance with the ambient air quality standards and PSD increments for the revised conditions. A request to modify these restrictions shall be accompanied by a new PSD Air Quality Analysis.

[Rules 62-210.200(PTE) and 62-212.400(PSD); and Permit Nos. PSD-FL-272B and 0510003-039-AC]

B.4 Startup, Shutdown and Malfunction Plans for Mill Boilers: Appendix K of this permit identifies the general procedures that will be used for startup, shutdown, and malfunction of the mill boilers including methods to minimize emissions. [Rules 62-4.070(3) and 62-210.700(1), F.A.C.; and Permit No. PSD-FL-272B]

## CONTROL EQUIPMENT AND TECHNIQUES

B.5 Wet Scrubber: To control emissions of particulate matter, the permittee shall install, operate, and maintain a Type D, Size 200 Joy Turbulaire wet impingement scrubber. In accordance with the manufacturer's recommendations, the wet scrubber control system shall be equipped with instrumentation to monitor the total pressure drop across the scrubber (inches of water column) and water flow rate (gpm). Such instrumentation shall be calibrated at least annually, properly maintained and operational at all times, except during periods of breakdown, repair or calibration. The permittee shall operate the wet scrubber in accordance with the CAM provisions of this subsection as well as the general provisions in Appendix H of this permit. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; and Permit No. PSD-FL-272B]

B.6 Other Control Techniques: To minimize emissions of sulfur dioxide and sulfuric acid mist, the boilers shall only fire the authorized low-sulfur fuels specified in this subsection. As provided in Appendix J of this permit, operators shall follow the good combustion practices that are generally applicable to all sugar mill boilers. In addition, operators shall use the following good combustion practices to minimize CO and VOC emissions while optimizing $NO_X$ emissions from Boiler 4.

a. The permittee shall calibrate, operate, and maintain process monitors to indicate the oxygen and carbon monoxide content of the exhaust flue gas in the boiler furnace. The oxygen process monitor shall include an alarm with a set point at 1.5% (minimum) flue gas oxygen content based on a 1-hour block average. The CO process monitor shall include an alarm with a set point at 3000 ppm (maximum) flue gas CO concentration based on a 1-hour block average. Each monitor shall display both the instantaneous and the 1-hour block average. Readouts of these process monitors shall be provided in the boiler control room.

b. All boiler operators and supervisors shall be properly trained to operate the boiler and pollution control equipment in accordance with the guidelines and procedures established by each equipment manufacturer. Power plant management shall instruct operations and maintenance personnel in proper boiler and scrubber operations so as to minimize stack emissions. This includes instruction for observing the oxygen and carbon monoxide process monitors to promote good combustion as well as adjusting operations in response to an alarm condition. All boiler operators and team leaders shall possess an operator certification from an independent agency equivalent to NIULPE 4$^{th}$ class.

c. The boiler operator will maintain steam rate at optimal or desired rate by controlling feed of bagasse fuel into the boiler. Combustion air to the boiler will be maintained at the highest possible level (resulting in sufficient excess air whenever feasible) in order to promote good combustion. The boiler operators shall periodically observe each process monitor and adjust the boiler operation, consistent with good combustion practices. The boiler operator, shift supervisor, and roving operator shall periodically view the smoke stack plume to visually confirm that good combustion is taking place. If an abnormal plume is observed, the operator will immediately take corrective action. The boiler operator will log the occurrence and duration of all such events in the boiler operation log, along with the corrective action taken.

d. If the alarm is tripped for either process monitor (low oxygen content or high CO concentration), the boiler operator shall take corrective actions consistent with good combustion practices. Corrective actions include, but are not limited to, adjusting the air-to-fuel ratio, adjusting the ratio of under-fire air to over-fire air, and firing some fuel oil in place of bagasse. For each such incident, the operator shall summarize the corrective actions taken and the approximate time when operation within the target parameter was regained. It is noted that the monitored flue gas carbon monoxide content is for the purpose of determining efficient combustion and may not be representative of the actual CO emissions from the stack. Operation outside of the specified operating range for either monitored parameter is not a violation of this permit, in and of itself. However, continued or frequent operation outside of the specified operating range for either monitored parameter without corrective action may be considered circumvention of "good combustion practices".

e. $NO_X$ emissions are to be optimized by the proper application of good combustion practices. However, the practices to minimize CO and VOC emissions may result in increased $NO_X$ emissions due to more excess air and higher combustion temperatures. Therefore, the practices to optimize $NO_X$ emissions are considered to be the same practices used to minimize CO and VOC emissions, as described above.

f. Appendix J of this permit specifies operational, maintenance and monitoring procedures that are generally applicable to all sugar mill boilers for maintaining good combustion.

[Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; and Permit No. PSD-FL-272B]

**EMISSION LIMITING STANDARDS**

B.7 CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 6.5 lb/MMBtu of total heat input based on a 3-run test average. [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

B.8 NOx Standard: As determined by EPA Method 7 or 7E, $NO_X$ emissions shall not exceed 0.20 lb/MMBtu of heat input from firing bagasse based on a 3-run test average. [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

B.9 Opacity Standard: As determined by DEP Method 9, visible emissions shall not exceed 20% opacity based on a six-minute average, except for one two-minute period per hour that shall not exceed 40% opacity. This standard excludes water vapor. *{Permitting Note: This standard is more stringent than that imposed by Rules 62-296.410(2)(b)1, F.A.C. for carbonaceous fuel burning equipment.}* [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

B.10 PM Standard: Particulate matter emissions shall not exceed 0.15 lb/MMBtu of heat input from bagasse firing nor 0.10 lb/MMBtu of heat input from oil firing based on a 3-run test average as determined by EPA Method 5. Compliance when firing both fuels shall be determined by prorating the emissions standards based on the heat input from each fuel. *{Permitting Note: This standard is more stringent than that imposed by Rules 62-296.410(2)(b)2, F.A.C. for carbonaceous fuel burning equipment.}* [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

B.11 $SO_2$ Standard: Sulfur dioxide emissions shall not exceed 0.06 lb/MMBtu of heat input from bagasse firing based on a 3-run test average as determined by EPA Methods 6, 6C or 8. This standard shall also serve as a surrogate for sulfuric acid mist (SAM) emissions, which are estimated to be 0.01 lb/MMBtu of heat input from bagasse firing as determined by EPA Method 8. Emissions of $SO_2$ and SAM from fuel oil firing are limited by the sulfur content restrictions specified by this permit. [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

B.12 VOC Standard: Volatile organic compound emissions shall not exceed 0.50 lb/MMBtu of total heat input (as propane) based on a 3-run test average as determined by EPA Method 18 and EPA Method 25A, modified to include a means of sample dilution. However, the sample shall not be diluted below the minimum detection limit for the flame ionization detector. Total VOC emissions shall be determined by EPA Method 25A and reported in terms of lb/MMBtu (as propane). EPA Method 18 shall be used to determine emissions of methane and reported in terms of lb/MMBtu (as propane). Emissions of regulated VOC shall be defined as the difference between the total VOC emissions and methane emissions reported in terms of lb/MMBtu (as propane). [Rule 62-212.400(BACT), F.A.C.; Permit No. PSD-FL-272B; and ASP No. 96-H-01]

## TESTING

B.13 General Testing Requirements: The boilers are subject to the applicable provisions of Appendix C, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

B.14 Test Methods: If required, stack tests shall be performed in accordance with the following methods or the most recent versions of these methods.

| EPA Method | Description of Method and Comments |
|---|---|
| 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. |
| 5 | Determination of PM Emissions from Stationary Sources |
| 6 or 6C | Measurement of $SO_2$ Emissions (Instrumental) |
| 7 or 7E | Measurement of NOx Emissions (Instrumental) |
| 8 | Determination of SAM and $SO_2$ Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity. The minimum observation period shall be no less than 60 minutes. |
| 10 | Measurement of CO Emissions (Instrumental). The CO test method shall be based on a continuous sampling train. |
| 18 | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissionsof methane and ethane from the THC emissions measured by Method 25A; otherwise, all THC emissions measured by EPA Method 25A will be assumed to be regulated VOC. |
| 19 | Calculation Method for NOx, PM, and $SO_2$ Emission Rates. Method shall be performed as necessary to support other methods. |
| 25A | Measurement of Gaseous Organic Concentrations (Flame Ionization) Method may be modified to include a means of sample dilution. However, the sample shall not be diluted below the minimum detection limit for the flame ionization detector. |

The above 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 and 62-297.401, F.A.C.; 40 CFR 60, Appendix A; and Permit No. PSD-FL-272B]

B.15 Combined Plumes, Alternate Method for Stack Opacity: It is possible that combined plumes from adjacent boilers will prevent a reliable determination of compliance with the opacity standard. If the permittee is unable to perform the scheduled annual visible emissions test because of combined plumes, the permittee shall record the scrubber pressure drop and water flow rate during each test run for particulate matter at 15-minute intervals. The test report shall note the attempt to perform the annual visible emissions test, the reason for not being able to complete the test and shall identify scrubber pressure drops and water flow rates recorded during each test run for particulate matter. [Rules 62-4.070(3), 62-213.440(1)(b) and 62-297.310(7)(a)4, F.A.C.]

B.16 Annual Compliance Tests: During each federal fiscal year (October 1$^{st}$ to September 30$^{th}$), the permittee shall conduct annual performance tests for CO, $NO_X$, PM, VOC and opacity to demonstrate compliance with the emissions standards specified in this subsection. All CO and $NO_X$ tests shall be conducted concurrently. [Rules 62-4.070(3), 62-212.400(PSD), and 62-297.310(7)(a)4, F.A.C.; and Permit No. PSD-FL-272B]

B.17 Compliance Tests Prior to Renewal: The permittee shall conduct tests for CO, $NO_X$, PM, $SO_2$, VOC, visible emissions and boiler thermal efficiency to demonstrate compliance with the emissions standards and conditions specified in this subsection.

a. All CO and $NO_X$ tests shall be conducted concurrently.

b. During each $SO_2$ performance test, the permittee shall sample and analyze the bagasse fuel for sulfur content. The sulfur content shall be used to calculate the potential uncontrolled $SO_2$ emissions as well as the control efficiency during the test. This information shall be submitted in the test report.

c. The boiler thermal efficiency shall be determined with the ASME boiler efficiency short form method or other equivalent method. This test shall demonstrate, in part, adherence to the maintenance provisions of the good combustion practices plan. If the test for boiler thermal efficiency indicates an efficiency of less than 50%, the permittee shall begin conducing annual tests. If maintenance and repair result in regaining a boiler thermal efficiency of 50% or more, testing may revert back to the federal fiscal year prior to renewal. [Rules 62-4.070(3), 62-212.400(PSD), and 62-297.310(7)(a)4, F.A.C.; and Permit No. PSD-FL-272B]

B.18 Tests After Substantial Modifications: Additional performance tests may be required after any substantial modification and appropriate shake-down period of the boiler or air pollution control equipment. Shakedown periods shall not exceed 90 days after re-starting the unit. [Rule 62-297.310(7)(a)4, F.A.C.; and Permit No. PSD-FL-272B]

B.19 Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the scrubber pressure drop, the scrubber water flow rate, the flue gas oxygen content, and the flue gas carbon monoxide content at 15 minute intervals. The permittee shall monitor and record the steam production rate, steam temperature, steam pressure, feed water flow rate, feed water temperature, feed water pressure, and oil flow rate and calculate and record the bagasse consumption rate and the heat input rate for each run. For each test run, the heat input rate shall be calculated from the steam production data and by assuming a 55% thermal efficiency for the boiler. [Rules 62-4.070(3) and 62-297.310(5), F.A.C.; and Permit No. PSD-FL-272B]

## MONITORING, RECORD KEEPING AND REPORTING

B.20 Monitoring Equipment: In accordance with the manufacturer's recommendations, the permittee shall calibrate, operate and maintain all monitoring equipment including: steam flow meters, steam integrators, strip chart recorders, pressure gages, manometers, scrubber water flow meters, fuel oil flow meters, and all other monitoring devices used to demonstrate compliance with the conditions of this permit. Each device shall be calibrated at least annually. All calibrations and repairs shall be recorded as part of the Daily

Operational Records. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; and Permit Nos. PSD-FL-272B and 0510003-039-AC]

B.21 Daily Operational Records: To demonstrate compliance with the performance requirements of this permit, the permittee shall record the following information in daily logs.

a. *Boiler Operations*: The permittee shall record the time and date the boiler undergoes startup, shutdown, or malfunction. The permittee shall also log the time the boiler has achieved or regained normal operation. Chart recorders shall continuously record the steam pressure (psig), steam temperature (° F) and steam production rate (pounds per hour). Alternatively, the permittee may install an automated device to record these parameters.

b. *Flue Gas Parameters*: The permittee shall record the oxygen and carbon monoxide contents of flue gas once normal operation is established after startup and at least once per hour of operation. Alternatively, the permittee may install an automated device to record these parameters.

c. *Wet Scrubber Parameters*: Once normal operation is established after startup, the permittee shall record the scrubber pressure drop (inches of water column) and water flow rate (gpm). Thereafter, the permittee shall record this information in accordance with the CAM provisions in this subsection and the general provisions in Appendix H of this permit. Alternatively, the permittee may install an automated device to record these parameters.

d. *Calibrations*: The permittee shall record in the daily log any monitoring equipment calibrations and repairs.

e. *Daily Summary*: For each day of operation, the permittee shall calculate and record the following by the end of the next workday.

(1) Operation: hours/day;
(2) Steam production rate: lb/day and lb/hour (daily average);
(3) Heat input: MMBtu/day and MMBtu/hour (daily average); and
(4) Fuel Oil Consumption: gallons/day.

All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any. [Rules 62-212.400(PSD) and 62-4.070(3), F.A.C.; and Permit Nos. PSD-FL-272B and 0510003-039-AC]

B.22 Monthly Operations Summary: Within ten calendar days of the end of each month, the permittee shall calculate and record the following information in a written or electronic log to demonstrate compliance with the performance requirements of this permit: hours of operation; steam production rate (lb); heat input rate (MMBtu); wet bagasse consumption rate (tons); total oil fired (gallons); and for any monitored parameters with missing records, the data availability (percent) for the month. These records shall indicate the amounts for the previous month and the consecutive 12-month rolling total. All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary ofthe incident and any corrective actions taken to regain proper operation, if any. [Rules 62-212.400(PSD) and 62-4.070(3), F.A.C.; and Permit No. PSD-FL-272B] [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and Permit Nos. PSD-FL-272B and 0510003-039-AC]

B.23 Fuel Monitoring Provisions: The permittee shall comply with the applicable fuel monitoring requirements specified in Appendix I (Fuel Monitoring) for each authorized fuel. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; and Permit No. 0510003-039-AC]

B.24 CAM Plan for Wet Scrubber: The permittee shall comply with the following CAM plan requirements as well as the general provisions specified in Appendix H of this permit.

| CAM Criteria | Indicator #1 | Indicator #2 |
|---|---|---|
| Indicator | Pressure drop across scrubber | Total scrubber water flow rate |
| Measurement Approach | Manometer (or equivalent) | Flow meter |
| Indicator Range | An excursion is defined as any pressure drop **below 6.0 inches of water column**. Excursions trigger inspection, corrective action, record keeping and reporting. | An excursion is defined as any flow rate **below 220 gallons per minute**. Excursions trigger inspection, corrective action, record keeping and reporting. |
| Data Representativeness | Manometer measures scrubber pressure drop with a minimum accuracy of ± 0.5 inches of water column (gage). | Flow meter measures scrubber flow rate with a minimum accuracy of ± 5% of total water flow. |
| Verification of Operational Status | NA | NA |
| QA/QC Procedures | Maintain equipment in accordance with manufacturer's recommendations. | Maintain equipment in accordance with manufacturer's recommendations. |
| Monitoring Frequency | Continuous readout | Continuous readout |
| Data Collection Procedures | Recorded at 4 hour intervals. | Recorded at 4 hour intervals. |
| Averaging Period | NA | NA |

In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. Automated recorders may be installed to satisfy the recording requirements. The permittee shall record any problems with operation of the wet scrubber and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; and 40 CFR 64]

B.25 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

This subsection addresses the following regulated emissions unit.

| EU No. | Emissions Unit Description |
|---|---|
| 014 | Boiler 7 is an Alpha Conal Model No. ATT-203-18 spreader-stoker, vibrating-grate boiler with a maximum steam production rate of 385,000 pounds per hour at 750° F and 600 psig. It fires primarily bagasse with distillate oil as a supplemental and alternate fuel. Particulate matter emissions are controlled by two parallel wet sand separators followed by an ABB electrostatic precipitator. Exhaust gases exit a stack that is 8.0 feet in diameter and 225 feet tall at 312° F with an average flow rate of296,657 acfm. |

## CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS

C.1 Permitted Capacity: Boiler 7 is authorized to fire bagasse as the primary fuel with wood chips and distillate oil used as auxiliary fuels. Boiler 7 shall not exceed the permitted capacities specified in the following table.

| Averaging Period | Steam Pressure [a] | Steam Temperature [a] | Steam Production (lb/hour) | Heat Input [b] (MMBtu/hour) | Wet Bagasse Firing [b] (tons/hour) |
|---|---|---|---|---|---|
| 1-hour | 600 psig | 750° F | 385,000 | 812 | 113 |
| 24-hour | 600 psig | 750° F | 350,000 | 738 | 103 |

a. Steam temperature and pressure are design parameters. Changes to these parameters shall be reported to the Department and may require a permit modification.

b. The maximum heat input and bagasse firing rates are estimated based on 55% thermal efficiency of the boiler; wet bagasse containing 55% moisture and a heat content of 3600 Btu/lb; and 1160 Btu (net) per pound of steam at 600 psig and 750° F with standard feed water conditions of 900 psig and 250° F.

c. The maximum distillate oil firing rate is 2417 gallons per hour, which produces approximately 225,000 pounds of steam per hour from the sole firing of distillate oil at a heat input rate of 326 MMBtu per hour.

d. Wood chips shall be fired at a heat input rate of no more than 369 MMBtu per hour based on a 24-hour average. The heat input rate from firing wood chips shall not exceed 1,616,220 MMBtu during any consecutive 12 months (equivalent to 25% of the maximum annual heat input rate).

The permittee shall maintain continuous monitoring records of the steam temperature, steam pressure, and steam production rate. [Rules 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; EPA alternative opacity monitoring plan approval dated February 1, 2008; and Permit Nos. PSD-FL-208A, 0510003-018-AC and PSD-FL-389A]

C.2 Authorized Fuels: Boiler 7 is authorized to fire the following fuels.

a. *Bagasse*: The primary fuel is bagasse, which is the fibrous byproduct remaining from the sugarcane after milling.

b. Wood Chips: Wood chips may be fired as a startup and restricted auxiliary fuel. Wood chips shall consist of clean dry wood and vegetative materials. The wood chips shall be substantially free of plastics, rubber, glass, painted wood, chemically treated wood, and non-combustible materials. The firing of any household garbage, hazardous wastes, or toxic materials is prohibited.

c. *Distillate Oil*: Any oil fired in this boiler shall be new No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. The oil firing system consists of multi-stage low-$NO_X$ burners and a burner management control system.

d. *On-specification Used Oil*: Incidental amounts of on-specification used oil (≤0.05% sulfur by weight) generated on site may be co-fired.

[Rules 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; and Permit Nos. PSD-FL-208A, 0510003-029-AC and PSD-FL-389A]

C.3 Restricted Operation: Boiler 7 operates primarily during the sugarcane crop season (October through April) and may operate during the off season (May through September) to support the sugar refinery. The hours of operation are not limited (8760 hours per year); however, no more than 4,500,000 gallons of distillate oil shall be fired during any consecutive 12-month period.

*{Permitting Note: The annual oil firing limit ensures that the annual capacity factor (as defined in 40 CFR 60.41b) remains below 10% and avoids applicability of the $NO_X$ standard in accordance with 40 CFR 60.44b(l)(1).}*

[Rules 62-210.200(PTE) and 62-212.400(12), F.A.C.; 40 CFR 60.44b(l)(1); and Permit Nos. PSD-FL-208A and 0510003-029-AC]

C.4 Startup, Shutdown and Malfunction Plans for Mill Boilers: Appendix K of this permit identifies the general procedures that will be used for startup, shutdown, and malfunction of the mill boilers including methods to minimize emissions. [Rules 62-4.070(3) and 62-210.700(1), F.A.C.]

## CONTROL EQUIPMENT AND TECHNIQUES

C.5 Sand Separators: The permittee shall operate and maintain two wet sand separators to remove large particles prior to the electrostatic precipitator. [Rules 62-4.070(3) and 62-210.200(PTE); and Permit No. PSD-FL-208A]

C.6 Electrostatic Precipitator: The permittee shall operate and maintain an electrostatic precipitator to achieve the PM standards specified in this subsection. The original design control efficiency is 98%. Exhaust from the outlet stack shall be maintained at a minimum of225 feet in height. [Rules 62-4.070(3) and 62-210.200(PTE); and Permit No. PSD-FL-208A]

C.7 Other Control Techniques:

a. *Low-Sulfur Fuels*: To minimize emissions of sulfur dioxide and sulfuric acid mist, the boilers shall only fire the authorized low-sulfur fuels specified in this subsection.

b. *Good Combustion Practices*: Appendix J of this permit specifies operational, maintenance and monitoring procedures that are generally applicable to all sugar mill boilers for maintaining good combustion.

[Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; and Permit No. PSD-FL-208A]

## EMISSION LIMITING STANDARDS

The "lb/hour" standards in the following conditions are based on the maximum 24-hour maximum heat input rate.

C.8 CO Standards: As determined by EPA Method 10, CO emissions shall not exceed 0.70 lb/MMBtu of heat input, 516 lb/hour and 2262 tons/year when firing bagasse. [Permit No. PSD-FL-208A]

C.9 NOx Standards: As determined by EPA Methods 7 or 7E, $NO_X$ emissions shall not exceed 0.25 lb/MMBtu of heat input, 185 lb/hour and 809 tons/year when firing bagasse. As determined by EPA Method 7E, $NO_X$ emissions shall not exceed 0.31 lb/MMBtu of heat input and 228.8 lb/hour when firing wood chips alone or in combination with other fuels. As determined by EPA Methods 7 or 7E, $NO_X$ emissions shall not exceed 0.20 lb/MMBtu of heat input when firing distillate oil. No periodic testing for oil firing is required. [Rule 62-204.800, 62-212.400(BACT), F.A.C.; 40 CFR 60.43b(f); and Permit Nos. PSD-FL-208A and 0510003-029-AC]

C.10 Opacity Standard: As determined by COMS or EPA Method 9, visible emissions shall not exceed 20% opacity based on a 6-minute average except for one 6-minute period per hour that shall not exceed 27% opacity. This standard excludes water vapor and applies when firing any combinations of fuels. [Rule 62-204.800, 62-212.400(BACT), F.A.C.; 40 CFR 60.43b(f); and Permit Nos. PSD-FL-208A, 0510003-029-AC and PSD-FL-389A]

C.11 PM/$PM_{10}$ Standard: As determined by EPA Method 5 or 17, PM emissions shall not exceed 0.03 lb/MMBtu of heat input, 22 lb/hour and 97 tons/year when firing any combinations of fuels. *{Permitting Note: All PM shall be assumed to be $PM_{10}$.}* [Rules 62-204.800, 62-296.410 and 62-212.400(BACT), F.A.C.; 40 CFR 60.43b; and Permit Nos. PSD-FL-208A, 0510003-029-AC and PSD-FL-389A]

C.12 SAM Standards: As determined by EPA Method 8, SAM emissions shall not exceed 0.017 lb/MMBtu of heat input, 13 lb/hour and 55 tons/year when firing bagasse. Compliance with the fuel sulfur specifications and $SO_2$ emissions limits shall serve as indicators of compliance. No periodic tests are required. [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-208A]

C.13 $SO_2$ Standards: As determined by EPA Methods 6, 6C or 8, $SO_2$ emissions shall not exceed 0.17 lb/MMBtu, 125 lb/hour and 550 tons/year when firing any combinations of fuels. [Rules 62-204.800, 62-296.410 and 62-212.400(BACT), F.A.C.; 40 CFR 60.43b; and Permit Nos. PSD-FL-208A and 0510003-029-AC]

C.14 VOC Standards: As determined by EPA Methods 18 and 25 or 25A, VOC emissions shall not exceed 0.212 lb/MMBtu of heat input, 157 lb/hour and 685 tons/year when firing bagasse. [Rule 62-212.400(BACT), F.A.C. and Permit Nos. PSD-FL-208A and 0510003-029-AC]

**TESTING**

C.15 Test Methods: If required, stack tests shall be performed in accordance with the following methods or the most recent versions of these methods.

| EPA Method | Description of Method and Comments |
|---|---|
| 1 - 4 | Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content Methods shall be performed as necessary to support other methods. |
| 5 or 17 | Determination of PM Emissions from Stationary Sources |
| 6 or 6C | Measurement of $SO_2$ Emissions (Instrumental) |
| 7 or 7E | Measurement of $NO_X$ Emissions (Instrumental) |
| 8 | Determination of SAM and $SO_2$ Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity |
| 10 | Measurement of CO Emissions (Instrumental). The CO test method shall be based on a continuous sampling train.} |
| 18 | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A; otherwise, all THC emissions measured by EPA Method 25A will be assumed to be regulated VOC. |
| 19 | Calculation Method for NOx, PM, and $SO_2$ Emission Rates. Method may be used to supplement other methods. |
| 25A | Measurement of Gaseous Organic Concentrations (Flame Ionization) Method may be modified to include a means of sample dilution. However, the sample shall not be diluted below the minimum detection limit for the flame ionization detector. |

The above 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 and 62-297.401, F.A.C.; 40 CFR 60, Appendix A; and Permit Nos. PSD-FL-272B and 0510003-018-AC]

C.16 General Testing Requirements: The boilers are subject to the applicable provisions of Appendix C, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

C.17 Annual Compliance Tests: During each federal fiscal year (October 1 - September 30), the permittee shall conduct performance tests when firing bagasse for CO, $NO_X$, PM, VOC and opacity to demonstrate compliance with the applicable standards. If wood chips are fired during the federal fiscal year, separate compliance tests when firing wood are required for nitrogen oxides, particulate matter and visible emissions. Since bagasse is the worst-case fuel with regard to particulate matter, annual tests for particulate matter and visible emissions when firing bagasse may also be used to demonstrate compliance with the standards for firing wood chips. Tests for PM and opacity shall be conducted simultaneously unless approval is obtained from the Compliance Authority. [Rule 62-297.310(7)(a), F.A.C. and Permit Nos. PSD-FL-208A, 0510003-029-AC and PSD-FL-389A]

C.18 Renewal Compliance Tests: The permittee shall conduct performance tests when firing bagasse for CO, $NO_X$, PM, $SO_2$, VOC and opacity to demonstrate compliance with the applicable standards prior to renewing the Title V permit (at least every 5 years). Tests for PM and opacity shall be conducted simultaneously unless approval is obtained from the Compliance Authority. Before conducting any emissions tests for renewal, the permittee shall determine the thermal efficiency of the boiler using the ASME short-form or equivalent procedure. The results of the emissions and thermal efficiency tests shall be provided with the application to renew the operation permit. [Rule 62-297.310(7)(a), F.A.C. and permit 0510003-029-AC]

C.19 Parametric Monitoring for Tests: The permittee shall continuously monitor and record the oil flow rate and production rate, temperature and pressure of the steam. At no less than 15-minute intervals, permittee shall record the: flow rate to the wet cyclones; the flow rate, temperature and pressure of the feed water; and the amperage and voltage to the electrostatic precipitator. For each test run, the permittee shall monitor and record the bagasse firing rate. For each test run, the permittee shall calculate and record: the heat input rate based on the thermal efficiency and the steam and feedwater parameters; and the total power input to the electrostatic precipitator based on the monitored amperage and voltage. If the most recent thermal efficiency test indicates a thermal efficiency below 50%, the test results shall be used to determine the heat input rate from firing bagasse; otherwise, a default value of 55% may be used. [Rules 62-4.070(3) and 62-297.310(5); and Permit No. PSD-FL-208A]

## MONITORING, RECORD KEEPING AND REPORTING

C.20 Monitoring Equipment: In accordance with the manufacturer's recommendations, the permittee shall calibrate, operate, and maintain the monitoring devices used to demonstrate compliance with the conditions of this permit, including: flow meters with integrators, pressure monitors, temperature monitors, strip chart recorders, oil flow meters, etc. Each device shall be calibrated at least annually. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; and Permit No. PSD-FL-208A]

C.21 Daily Operational Records: To demonstrate compliance with the performance requirements of this permit, the permittee shall record the following information in daily logs.

a. *Boiler Operations*: Chart recorders shall continuously record the steam pressure (psig), steam temperature (° F), and steam production rate (pounds per hour). Alternatively, the permittee may install an automated device to record these parameters.

b. *ESP Parameters*: The permittee shall maintain records of the amperage, voltage and total secondary power input to the electrostatic precipitator. The permittee shall comply with the CAM plan specified in this subsection as well as the general provisions in Appendix H of this permit.

c. For each 24-hour block of operation (midnight to midnight), the permittee shall maintain records of the amount of wood chips fired to demonstrate compliance with the heat input restrictions of this permit.

d. For each 24-hour block of operation (midnight to midnight), the permittee shall calculate and record the heat input rate from wood chips.

All records shall indicate the date and time the information was recorded, and in the case of manual recordings, the name of the person who recorded the information. For data that indicates operation outside of the specified permitted levels of the above parameters, the permittee shall record a summary of the incident and any corrective actions taken to regain proper operation, if any. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C. and Permit No. PSD-FL-389A]

C.22 Alternative Opacity Monitoring Plan: In lieu of the continuous opacity monitoring requirements of 40 CFR 60.48b, EPA Region 4 approved an alternative opacity monitoring plan as specified in the CAM provisions of this subsection. The Department may require the permittee to install and operate a continuous opacity monitoring system for failure to regularly comply with the opacity standard. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; 40 CFR 60.13(i) and 60.48b(a); Permit Nos. PSD-FL-208A and PSD-FL-389A; and EPA approval dated February 1, 2008]

C.23 Monthly Operations Summary: Within ten calendar days of the end of each month, the permittee shall calculate and record the following information in a written or electronic log to demonstrate compliance with the performance requirements of this permit: hours of operation; steam production rate (lb); heat input rate (MMBtu); wet bagasse consumption rate (tons); and total oil fired (gallons). These records shall indicate the amounts for the previous month and the consecutive 12-month rolling total. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; and Permit No. PSD-FL-208A]

C.24 Fuel Monitoring Requirements: The permittee shall comply with the applicable fuel monitoring requirements specified in Appendix I (Fuel Monitoring) for each authorized fuel. [Rules 62-4.070(3) and 62-210.370(3), F.A.C. and Permit No. 0510003-029-AC]

C.25 Power Production: The permittee shall maintain records of the amount of any electrical power (MW) and the percentage of electrical power output distributed to any utility power distribution system. [Permit No. PSD-FL-208A]

C.26 CAM Plan, ESP: The permittee shall comply with the following CAM plan.

| CAM Criteria | Indicator #1 |
|---|---|
| Indicator | Total ESP secondary power input |
| Measurement Approach | Total secondary power input is calculated from the secondary current and voltage to each ESP field as monitored with an amp/volt meter. |
| Indicator Range | An excursion is defined as any total secondary power input **below 38 kW**. Excursions trigger inspection, corrective action, record keeping and reporting. |
| Data Representativeness | Accuracy of amp/volt meter is ± 1 milliampere (mA) and ± 1 kilovolt (kV) |
| Verification of Operational Status | NA |
| QA/QC Procedures | Maintain equipment in accordance with manufacturer's recommendations. |
| Monitoring Frequency | Continuous monitoring of secondary current and voltage to each ESP field |

| CAM Criteria | Indicator #1 |
|---|---|
| Data Collection Procedures | Based on continuous monitoring data, calculate and record a 3-hour block average. |
| Averaging Period | 3-hour block average |

In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. The permittee shall record any problems with operation of the ESP and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; 40 CFR 64; and EPA Region 4 approval dated February 1, 2008]

C.27 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. For each test run, the report shall also indicate the total heat input rate, the heat input rate from firing each fuel, the steam production rate, and the secondary power input to the electrostatic precipitator. [Rule 62-297.310, F.A.C. and Permit No. PSD-FL-389A]

C.28 Semiannual Report - Oil Firing: Within 30 days following each semiannual period (January to June and July to December), the permittee shall submit to the Compliance Authority: the distillate oil consumption for each month and the 12-month rolling total (gallons); and the certified vendor fuel analysis for each delivery of distillate oil during the reporting period. [40 CFR 60.49b(w)]

## OTHER APPLICABLE REQUIREMENTS

C.29 NSPS Provisions: Boiler 7 is subject to the applicable New Source Performance Standards of Subparts A and Db in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix L of this permit summarizes these provisions. [Rule 62-204.800, F.A.C.]

This subsection addresses the following regulated emissions unit.

| ID | Emission Unit Description |
|---|---|
| 028 | Boiler 8 is a membrane-wall boiler with balanced-draft stoker, over-fire air, rotating feeders, and pneumatic spreaders. At a maximum heat input rate of 1077 MMBtu per hour(24-hour average), the maximum continuous steam production is 575,000 pounds per hour (24-hour average) of superheated steam at 600 psig and 750° F for use in the sugar mill and refinery. The primary fuel is bagasse. Wood chips are fired as an alternate or supplemental fuel. Distillate oil is fired as a restricted alternate fuel for startup and supplemental uses. Bottom ash is removed to ash ponds by a submerged conveyor. Particulate matter is controlled by cyclone collectors followed by an ESP. Nitrogen oxides are reduced by a urea-based selective non-catalytic reduction system. Exhaust gases exit a stack with a maximum diameter of 10.9 feet and a minimum height of 199 feet at 255° F. At capacity, the approximate flow rate is 437,000 acfm at 5.5% oxygen (245,258 dscfm at 7% oxygen). Emissions of carbon monoxide and nitrogen oxides are monitored and recorded by continuous emissions monitoring systems (CEMS). |

## CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS

D.1 Boiler Capacities and Restrictions: Rotating feeders, pneumatic spreaders, a traveling grate, and overfire air are used to fire the primary fuel of bagasse and/or wood chips. Low-$NO_X$ burners are used to fire distillate oil as a restricted alternate fuel for startup and supplemental uses. The maximum oil firing rate is 4161 gallons per hour (equivalent to 562 MMBtu per hour). With a thermal efficiency of 62%, Boiler 8 is designed to generate 633,000 pounds per hour from a heat input rate of 1185 MMBtu per hour (1-hour averages). The hours of operation are not restricted (8760 hours/year). Boiler 8 shall not exceed the following operational levels.

a. 13,800,000 pounds of steam per day (equivalent to 575,000 pounds of steam per hour and 1077 MMBtu per hour based on 24-hour averages);

b. 3.6135 x $10^{+09}$ pounds of steam per consecutive 12 months (equivalent to 6,767,100 MMBtu per year);

c. 2,830,356 MMBtu of heat input per consecutive 12 months from firing wood chips (equivalent to 30% of the maximum annual heat input rate);

d. 99,864 gallons of distillate oil per day (equivalent to 13,488 MMBtu per day); and

e. 6,073,600 gallons of distillate oil per consecutive 12 months (equivalent to 819,936 MMBtu per year).

*{Permitting Note: The short-term restrictions form the basis of the Air Quality Analysis. The restriction on annual steam production is a surrogate for heat input and allowed the project to avoid PSD applicability for CO emissions. The annual oil firing restriction results in an annual capacity factor of 10% or less, which avoids specific requirements in NSPS Subpart Db.}*

[Rules 62-4.070(3), 62-212.400(PSD) and 62-210.200(PTE), F.A.C.; NSPS Subpart Db; EPA alternative opacity monitoring plan approval dated May 13, 2008; and Permit No. PSD-FL-333D]

D.2 Authorized Fuels: Boiler 8 is authorized to fire the following fuels.

a. *Bagasse*: The primary fuel is bagasse, which is the fibrous byproduct remaining from the sugarcane after milling.

b. Wood Chips: Wood chips may be fired as a startup and auxiliary fuel. Wood chips shall consist of clean dry wood and vegetative materials. The wood chips shall be substantially free of plastics, rubber, glass, painted wood, chemically treated wood, and non-combustible materials. The firing of any household garbage, hazardous wastes, or toxic materials is prohibited.

c. *Distillate Oil*: Any oil fired in this boiler shall be new No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight.

d. *On-specification Used Oil*: Incidental amounts of on-specification used oil (≤0.05% sulfur by weight) generated on site may be co-fired.

[Rules 62-212.400(PSD) and 62-210.200(PTE), F.A.C.; and Permit No. PSD-FL-333D]

D.3 Startup, Shutdown and Malfunction Plans for Mill Boilers: Appendix K of this permit identifies the general procedures that will be used for startup, shutdown, and malfunction of the mill boilers including methods to minimize emissions. [Rules 62-4.070(3) and 62-210.700(1), F.A.C.]

**CONTROL EQUIPMENT AND TECHNIQUES**

D.4 Air Pollution Control Equipment: Emissions from Boiler 8 are controlled by the following equipment.

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

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

c. *SNCR*: The permittee shall operate and maintain a urea-based selective non-catalytic reduction (SNCR) system to reduce $NO_X$ emissions in the flue gas exhaust and achieve the nitrogen oxides emissions standards specified in this permit. The system includes 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 are determined based on parameters such as the current injection rate, furnace temperature profile, fuels, steam load, oxygen level, CO level and $NO_X$ emissions.

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

D.5 Other Control Techniques: To minimize emissions of sulfur dioxide and sulfuric acid mist, the boilers shall only fire the authorized low-sulfur fuels specified in this subsection. As provided in Appendix J of this permit, operators shall follow the good combustion practices that are generally applicable to all sugar mill boilers. To the extent practicable, the permittee shall maintain the following flue gas levels as good combustion practices.

a. *Oxygen Levels*: The permittee shall maintain and operate a flue gas oxygen monitor on Boiler 8. When firing bagasse during normal operation, the oxygen content of the boiler exhaust is expected to range from 3% and 6%. High fuel moisture, high ash content, and low load conditions may result in higher flue gas oxygen contents (5% - 7%). When firing only distillate oil, the oxygen content of the boiler exhaust is expected to range from 4% to 5% 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. *CO Levels*: Carbon monoxide is an indicator of incomplete fuel combustion. In addition to insufficient oxygen, high fuel moisture, high ash content and low load conditions may result in elevated levels of carbon monoxide. When firing bagasse and/or wood chips during normal operation, the boiler exhaust CO content is expected to average approximately 400 ppmvd @ 7% oxygen. The operator shall use the measured CO emissions at the stack as an indicator of the combustion efficiency and adjust boiler operating conditions as necessary. The stack exhaust is expected to be 1% - 2% oxygen content higher than the boiler exhaust due to infiltration from the entire system.

The stack exhaust oxygen content is expected to be 1% - 2% higher than the boiler exhaust due to infiltration from the entire system. When firing bagasse and/or wood chips, many factors may affect efficient combustion. The above levels represent adherence to good combustion practices under normal operating conditions. Operation outside these levels is not a violation in and of itself. Repeated operation beyond these levels without taking corrective actions to regain good combustion could be considered "circumvention" in accordance with Rule 62-210.650, F.A.C.

[Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

**EMISSION LIMITING STANDARDS**

D.6 Standards Based on Compliance Tests: The following emission standards apply when firing bagasse, wood chips, distillate oil, or a combination of these fuels under normal operation at steady-state conditions. The mass emission rates (pounds per hour) are based on the maximum 24-hour heat input rate. Unless otherwise specified, compliance with these standards shall be based on the average of three test runs conducted under steady-state conditions at permitted capacity.

a. *Ammonia Slip Standard*: As determined by EPA Conditional Test Method CTM-027, ammonia slip shall not exceed 20 ppmvd @ 7% oxygen.

b. *CO Standard*: To the extent practicable, short term emissions of CO emissions shall be controlled by implementing the good combustion and operating practices identified in this subsection.

c. *Opacity Standard*: As determined by COMS or EPA Method 9 observations, visible emissions shall not exceed 20% based on a 6-minute average. This standard excludes water vapor and applies when firing any combinations of fuels.

d. *PM Standard*: As determined by EPA Method 5 stack test, PM emissions shall not exceed 0.025 lb/MMBtu and 26.9 pounds per hour.

e. *$SO_2$ Standard*: As determined by EPA Method 6C stack test, $SO_2$ emissions shall not exceed 0.06 lb/MMBtu and 64.6 pounds per hour. This emission standard serves as a surrogate for sulfuric acid mist (SAM) emissions.

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

{Permitting Note: The standards for ammonia slip, opacity, PM, $SO_2$ and VOC are BACT standards. The SO2 standard also serves as a surrogate BACT for SAM emissions.} [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

D.7 Standards Based on CEMS: The following emission standards apply when firing bagasse, wood chips, distillate oil or a combination of these fuels and under all load conditions.

a. *CO Standards*:

1) As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 7% oxygen based on a 30-day rolling average excluding the following periods: startup, shutdown, malfunction and operation at less than 50% of permitted capacity.

2) As determined by CEMS data, CO emissions shall not exceed 1285 tons during any consecutive 12 months including periods of startup, shutdown and malfunction. *{Permitting Note: Compliance with the annual mass emission standard ensures that the original project is not subject to PSD preconstruction review for CO emissions.}*

[Rules 62-4.070(3) and 62-212.400 (12), F.A.C.; and Permit No. PSD-FL-333D]

b. *NOx Standard*: 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 (BACT), F.A.C.; and Permit No. PSD-FL-333D]

D.8 Excess Emissions for CO, NOx, and Opacity: 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*:

1) Each 30-day rolling average shall include all valid CEMS data except data collected during the following periods: periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities or operation at less than 50% of its permitted capacity. Any period for which the monitoring system is out of control and data are not available for required calculations constitute a deviation from the monitoring requirements.

2) Each 12-month rolling total shall include all valid CEMS data including startup, shutdown and malfunction.

b. *NOx Emissions*: $NO_X$ CEMS data collected during startup, shutdown, malfunction and authorized periods of uncontrolled $NO_X$ monitoring (item #4 below) 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 (up to eight 15-minute CEMS blocks or quadrants of an hour). The permittee shall notify the Compliance Authority within one working day of detecting the malfunction; and

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

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

CO and $NO_X$ CEMS data excluded due to startup, shutdown, malfunction or authorized periods of uncontrolled $NO_X$ monitoring shall be summarized and reported in the "Quarterly CO and $NO_X$ Emissions Report" required by this permit.

*{Permitting Note: Because compliance is continuously demonstrated by CEMS data, allowances for CO and $NO_X$ are provided during specific periods of operation in which the control device or technique may not be fully functional. Similarly, an alternate standard is identified for opacity during startup and shutdown because compliance is readily observable. As $SO_2$ emissions are a function of the fuel sulfur, it is not expected that startups or shutdowns would cause excess emissions of this pollutant. During startups and shutdowns, it is possible that PM and VOC emissions could exceed the "lb/MMBtu" emissions standards. However, there is reason to believe that the mass emission rates (lb/hour) of these pollutants will not exceed the specified standards due to the reduced 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 be determined by the test methods and procedures specified in this subsection. The Department's rules and permits cannot waive or supersede a federal requirement.}*

## TESTING

D.9 Test Methods: If required, stack tests shall be performed in accordance with the following methods or the most recent versions of these methods.

| EPA Method | Description of Method and Comments |
|---|---|
| CTM-027 | Measurement of Ammonia Slip. 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 Methods shall be performed as necessary to support other methods. |
| 5 | Determination of Particulate Emissions from Stationary Sources |
| 6C | Measurement of $SO_2$ Emissions (Instrumental) |
| 7E | Measurement of $NO_X$ Emissions (Instrumental) |
| 9 | Visual Determination of the Opacity |
| 10 | Measurement of Carbon Monoxide Emissions (Instrumental) The CO test method shall be based on a continuous sampling train. |
| 18 | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) Optionally, EPA Method 18 may be used 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 SO2 Emission Rates. Method may be used to supplement other methods. |
| 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 and Permit No. PSD-FL-333D]

D.10 General Testing Requirements: The boilers are subject to the applicable provisions of Appendix C, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

D.11 Annual Stack Tests: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct compliance stack tests for ammonia slip, PM, VOC and opacity. Tests shall be conducted between 90% and 100% of the maximum 24-hour continuous heat input rate when firing only bagasse or bagasse with wood chips. Data from the CO CEMS shall be reported for each run of the required tests for $NO_X$ and VOC emissions. Data from the $NO_X$ CEMS shall be reported for each run of the required tests for ammonia slip. 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. [Rules 62-212.400 (PSD) and 62-297.310(7)(a) and (b), F.A.C.; and Permit No. PSD-FL-333D]

D.12 Renewal Compliance Tests: Before renewal of this Title V air operation permit, the permittee shall conduct a compliance test for $SO_2$ emissions when firing only bagasse. In addition, the permittee shall determine the thermal efficiency of the boiler when firing only bagasse using the ASME short-form or equivalent procedure before conducting the $SO_2$ test and any required annual compliance tests in the year before renewal of the Title V air operation permit. The results of the emissions and thermal efficiency tests shall be provided with the application to renew the Title V air operation permit. [Rule 62-4.070(3), F.A.C. and Permit No. PSD-FL-333D]

D.13 Parametric Monitoring for Tests: The permittee shall continuously monitor and record the oil flow rate and production rate, temperature and pressure of the steam. At no less than 15-minute intervals, permittee shall record the: flow rate and pressure drop to the wet cyclones; the flow rate, temperature and pressure of the feed water; and the amperage and voltage to the electrostatic precipitator. The bagasse and wood chip fuel firing rate (tons per hour) shall be calculated and recorded based on the steam parameters and the heating value of this fuel. For each test run, the permittee shall calculate and record: the heat input rate based on the thermal efficiency and the steam and feedwater parameters; and the total power input to the electrostatic precipitator based on the monitored amperage and voltage. The actual heat input rate shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the boiler thermal efficiency. If the most recent thermal efficiency test indicates a thermal efficiency below 56%, the test results shall be used to determine the heat input rate from firing bagasse; otherwise, a default value of 62% may be used. [Rules 62-4.070(3) and 62-297.310(5); and Permit No. PSD-FL-333D]

**MONITORING, RECORD KEEPING AND REPORTING**

D.14 CEMS: The permittee shall calibrate, operate and maintain continuous emission monitoring systems (CEMS) to measure and record concentrations of CO, $NO_X$, and oxygen 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.

a. *CO Monitors*: The CO monitor 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 and shall be based on a continuous sampling train. Quality assurance procedures shall conform to the requirements of Appendix F in 40 CFR 60.

b. *$NO_X$ Monitors*: The $NO_X$ monitor 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. $NO_X$ shall be expressed "as $NO_2$." 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 $NO_X$ monitor location to correct measured CO and $NO_X$ emissions to the required oxygen concentrations. The oxygen 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*: Each 1-hour block average shall begin at the top of an 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. Except for data authorized to be excluded, 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 permittee shall use at least one of the following methods:

1) 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), or

2) The permittee may estimate the flue gas moisture content as 26.0% for the crop season (high load operation) and 22.7% for the off-crop season (low-load operation). In addition to annual emissions compliance tests conducted at capacity, the permittee shall conduct three tests runs (30 minutes per

test run) to determine the flue gas moisture content (EPA Method 4) at low-load operation (less than 50% of permitted capacity) during each federal fiscal year. Whenever new data for the flue gas moisture content becomes available, the permittee shall adjust these estimates for use in determining emissions rates and report the new moisture content estimates to the Compliance Authority. [Letter of Authorization No. 0510003-047-AC]

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 the applicable emissions standard.

e. *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. Certain emissions data recorded during specifically defined episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. D.8 in this subsection. 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.

f. *30-Day Averages*: 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 the applicable emissions standard.

g. *CO Emissions Cap*: For each day (midnight to midnight), the CEMS shall record the total CO mass emissions rate (pounds per day). The 12-month rolling total shall be the sum of the daily mass emission rates reported as "tons per consecutive 12 months".

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

[Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

D.15 Alternative Opacity Monitoring Plan: In lieu of the continuous opacity monitoring requirements of 40 CFR 60.48b, EPA Region 4 approved an alternative opacity monitoring plan as specified in the CAM provisions of this subsection. The Department may require the permittee to install and operate a continuous opacity monitoring system for failure to regularly comply with the opacity standard. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.; 40 CFR 60.13(i) and 60.48b(a); Permit No. PSD-FL-333D; and EPA approval dated May 13, 2008]

D.16 SNCR Urea Injection: In accordance with the manufacturer's specifications, the permittee shall 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 $NO_X$ standard over the range of load conditions by comparing $NO_X$ emissions with urea flow rates. During $NO_X$ monitor downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

D.17 Cyclones: In accordance with the manufacturer's recommendations, the permittee shall calibrate, operate and maintain the following equipment: flow meter to monitor the water flow rate (gph) for each wet cyclone and a manometer (or equivalent) to monitor the pressure drop (inches of water) across each cyclone. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

D.18 Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall 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. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.; and Permit No. PSD-FL-333D]

D.19 Fuel Monitoring Requirements: The permittee shall comply with the applicable fuel monitoring requirements specified in Appendix I (Fuel Monitoring) for each authorized fuel. [Rules 62-4.070(3) and 62-210.370(3), F.A.C. and Permit No. PSD-FL-333D]

D.20 CAM Plan for ESP: The permittee shall comply with the following CAM plan.

| CAM Criteria | Indicator #1 |
|---|---|
| Indicator | Total ESP secondary power input |
| Measurement Approach | Total secondary power input is calculated from the secondary current and voltage to each ESP field as monitored with an amp/volt meter. |
| Indicator Range | An excursion is defined as any total secondary power input **below 25 kW during the crop season (October through April) and 18 kW during the off season (May through September)**. Excursions trigger inspection, corrective action, record keeping and reporting. |
| Data Representativeness | Accuracy of amp/volt meter is ± 1 milliampere (mA) and ± 1 kilovolt (kV) |
| Verification of Operational Status | NA |
| QA/QC Procedures | Maintain equipment in accordance with manufacturer's recommendations. |
| Monitoring Frequency | Continuous monitoring of secondary current and voltage to each ESP field |
| Data Collection Procedures | Based on continuous monitoring data, calculate and record a 3-hour block average. |
| Averaging Period | 3-hour block average |

In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. The permittee shall record any problems with operation of the ESP and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; and 40 CFR 64]

D.21 Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month of operation: hours of operation, distillate oil consumption, pounds of steam per month, and the updated 12-month rolling totals for each of these operating parameters. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

D.22 Test Notifications, Records and Reports: Appendix C of this permit specifies the general requirements for test notifications, records and reports. In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (MMBtu/hour), calculated bagasse firing rate (tons/hour), wood chip firing rate (tons/hour), and emission rates (lb/MMBtu and ppmvd @ 7% oxygen). [Rule 62-297.310, F.A.C. and Permit No. PSD-

FL-333D]

D.23 Quarterly Report - CO and NOx Emissions: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing CO and $NO_X$ emissions including periods of startups, shutdowns, malfunctions, authorized uncontrolled $NO_X$ emissions monitoring and CEMS systems monitor availability for the previous quarter. 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. See Appendix L of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

D.24 Semiannual Report - Oil Firing: Within 30 days following each semiannual period (January to June and July to December), the permittee shall submit to the Compliance Authority: the distillate oil consumption for each month and the 12-month rolling total (gallons); the certified vendor fuel analysis for each delivery of distillate oil during the reporting period. [40 CFR 60.49b(w)]

## OTHER APPLICABLE REQUIREMENTS

D.25 NSPS Provisions: Boiler 8 is subject to the applicable New Source Performance Standards of Subparts A and Db in 40 CFR 60 for "Industrial-Commercial-Institutional Steam Generating Units". Appendix L of this permit summarizes these provisions. [Rule 62-204.800, F.A.C.; 40 CFR 60, NSPS Subpart A and Db; and Permit No. PSD-FL-333D]

This subsection addresses the following regulated emissions unit.

| EU No. | Emission Unit Description |
|---|---|
| 027 | Biomass handling and storage |

## EQUIPMENT AND CONTROL TECHNIQUES

E.1 Biomass Handling and Storage Equipment: To minimize fugitive particulate matter, conveyors shall be covered and landing zones provided for conveyor transfer points. The conveyor system shall be completely covered or enclosed except for the transfer points to/from the material stockpile and the point associated with conveying material from conveyor C9A to C9B in the drying mill. The existing bagacillo system pneumatically collects a small fraction of bagasse from the conveyor system and transfers fine particles suspended in the gas stream to the Boiling House. The bagacillo cyclone separates particles from the gas stream, which are used as part of the cake material on the vacuum filters. The bagacillo system is an existing, unregulated emissions unit. [Rule 62-212.400 (BACT), F.A.C. and Permit Nos. PSD-FL-333D and PSD-FL-389A]

**Subsection F. Granular Carbon Regenerative Furnace**

This subsection addresses the following regulated emissions unit.

| EU No. | Emission Unit Description |
|---|---|
| 017 | Granular carbon regenerative furnace is used to remove colorants and VOC emissions during the decolorization process in the sugar refinery. The granular carbon regenerative furnace is designed for a capacity of 40,000 pounds of cane sugar per day. The furnace then drives off colorants and VOC emissions from the carbon and regenerates the carbon for reuse. A direct flame afterburner controls VOC emissions and a wet venturi/tray scrubber system controls PM emissions. The plant identifies this point source as S-12.<br>*Afterburner*: Zero Hearth Type (10'-9" OD x 8 HTH) furnace manufactured by BSP Thermal Systems, Inc. designed for the following specifications: 1200° F to 1400° F design temperature; 10,600 to 16,300 acfm flow rate; 0.5 to 0.75 seconds exhaust gas residence time; and a 92% destruction efficiency. The furnace and afterburner will fire approximately 90 gallons per hour and a maximum of 788,400 gallons per year.<br>*Wet Scrubber System*: High energy venturi wet scrubber with tray type wet scrubber designed for the following specifications: 160° F and 4300 acfm outlet gas flow; 12 to 30 inches of water across venturi scrubber with a 36 gpm flow rate; 3 to 8 inches of water across the tray scrubber with 230 gpm flow rate; and a 97% particulate removal efficiency. |

**CAPACITY, FUELS AND PERFORMANCE RESTRICTIONS**

F.1 Authorized Fuel: Only distillate oil containing no more than 0.05% sulfur by weight shall be fired in the granular carbon regenerative furnace and associated afterburner. [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

F.2 Hours of Operation: The hours of operation for this unit are not restricted (8760 hours per year). [Rule 62-210.200(PTE), F.A.C. and Permit No. PSD-FL-272B]

**CONTROL EQUIPMENT AND TECHNIQUES**

F.3 GCRF Afterburner: The permittee shall operate and maintain an afterburner designed to destroy at least 92% of the VOC emissions during regeneration of the carbon bed as part of the decolorization process. The afterburner shall be designed with a control temperature of between 1200° F and 1400° F and an exhaust gas residence time of between 0.5 and 0.75 seconds. Excluding initial startup, shutdown, and malfunction, the afterburner temperature shall be maintained at 1200° F or higher except for up to 6 total minutes each hour during which the temperature shall not fall below 1000°F. [Rule 62-212.400 (BACT), F.A.C. and Permit No. PSD-FL-272B]

F.4 GCRF Wet Scrubber: The permittee shall install, operate, and maintain a wet venturi/ tray scrubber system designed to control at least 97% of the maximum particulate emissions during regeneration of the carbon bed as part of the decolorization process. The venturi scrubber shall be designed for a pressure drop of between 12 to 30 inches of water column. The wet tray scrubber shall be designed for a pressure drop of between 3 to 8 inches of water column. Separate manometers (or equivalent devices) shall be installed, operated, and maintained to indicate the pressure drop across each control device. Operation outside of the specified operating range for any monitored parameter is not a violation of this permit, in and of itself. However, continued operation outside of the specified operating range for any monitored parameter without corrective action may be considered circumvention of the air pollution control equipment. [Rule 62-212.400 (BACT), F.A.C. and Permit No. PSD-FL-272B]

**EMISSION LIMITING STANDARDS**

F.5 PM Standard: As determined by EPA Method 5, PM emissions shall not exceed 0.7 pounds per hour from the granular carbon regenerative furnace. [Rule 62-212.400 (BACT), F.A.C. and Permit No. PSD-FL-272B]

F.6 Opacity Standard: As determined by EPA Method 9, visible emissions shall not exceed 10% opacity excluding water vapor. [Rule 62-212.400 (BACT), F.A.C. and Permit No. PSD-FL-272B]

F.7 VOC Standard: As determined by EPA Method 25A, VOC emissions shall not exceed 1.0 pound per hour (reported as propane) from the granular carbon regenerative furnace. Optionally, EPA Method 18 may be conducted concurrently to deduct methane. [Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-272B]

**TESTING**

F.8 General Testing Requirements: The emissions unit is subject to the applicable provisions of Appendix C, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

F.9 Test Methods: If required, stack tests shall be performed in accordance with the following methods or the most recent versions of these methods.

| EPA Method | Description of Method and Comments |
|---|---|
| 1 - 4 | Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content Methods shall be performed as necessary to support other methods. |
| 5 | Determination of Particulate Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity |
| 18 | Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A. |
| 25A | Measurement of Gaseous Organic Concentrations (Flame Ionization) |

These 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]

F.10 Annual Stack Tests: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct compliance tests for opacity. Compliance with the PM and VOC emissions standards shall be assumed as long as the emissions unit remains in compliance with the opacity standard as well as the control equipment monitoring requirements for the afterburner and wet scrubbing system. [Rules 62-212.400 (PSD) and 62-297.310(7), F.A.C.; and Permit No. PSD-FL-272B]

F.11 Renewal Compliance Tests: Prior to renewal of the Title V permit, the permittee shall conduct compliance stack tests for opacity, PM and VOC emissions. [Rules 62-212.400 (PSD) and 62-297.310(7), F.A.C.; and Permit No. PSD-FL-272B]

F.12 Tests After Substantial Modifications: All performance tests shall also be conducted after any substantial modification and appropriate shake-down period of the emission unit or air pollution control equipment. Shakedown periods shall not exceed 90 days after re-starting the unit. [Rule 62-297.310(7)(a)4., F.A.C. and Permit No. PSD-FL-272B]

F.13 Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the afterburner temperature and wet scrubber pressure differentials at 15-minute intervals. [Rule 62-297.310(5), F.A.C. and Permit No. PSD-FL-272B]

**MONITORING, RECORD KEEPING AND REPORTING**

F.14 CAM Plan, Wet Scrubbers: The permittee shall comply with the following CAM plan.

| CAM Criteria | Indicator #1 (Venturi Scrubber) | Indicator #2 (Wet Tray Scrubber) |
|---|---|---|

| CAM Criteria | Indicator #1 (Venturi Scrubber) | Indicator #2 (Wet Tray Scrubber) |
|---|---|---|
| Indicator | Pressure drop across venturi scrubber | Pressure drop across wet tray scrubber |
| Measurement Approach | Manometer (or equivalent) | Manometer (or equivalent) |
| Indicator Range | An excursion is defined as any pressure drop **below 20 inches of water column**. Excursions trigger inspection, corrective action, record keeping and reporting. | An excursion is defined as any pressure drop **below 6.5 inches of water column**. Excursions trigger inspection, corrective action, record keeping and reporting. |
| Data Representativeness | Manometer measures scrubber pressure drop with a minimum accuracy of ± 0.5 inches of water column (gage). | Manometer measures scrubber pressure drop with a minimum accuracy of ± 0.5 inches of water column (gage). |
| Verification of Operational Status | NA | NA |
| QA/QC Procedures | Maintain equipment in accordance with manufacturer's recommendations. | Maintain equipment in accordance with manufacturer's recommendations. |
| Monitoring Frequency | Continuous readout | Continuous readout |
| Data Collection Procedures | Recorded at 4 hour intervals. | Recorded at 4 hour intervals. |
| Averaging Period | NA | NA |

In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. The permittee shall record any problems with operation of the wet scrubbers and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; and 40 CFR 64]

F.15 Operations Log: At least once per shift, the permittee shall observe and record the afterburner temperature and the wet scrubber pressure differentials. The permittee may install automated equipment to continuously record these parameters. For any monitored parameters with missing records, the permittee shall calculate and record the data availability (in percent) for each month. [Rule 62-4.070(3), F.A.C.]

F.16 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

**Subsection G. Miscellaneous Sugar Refinery Sources**

This subsection addresses the following regulated emissions units.

| EU No. | Emissions Unit Description |
|---|---|
| 015 | VHP sugar dryer controlled by baghouse (S-11) |
| 016 | White sugar dryer No. 1 controlled by baghouse (S-10) |
| 018 | Vacuum systems with baghouses for: screening/distribution system (S-1); 100 lb bagging operation (S-2); and 5 lb bagging operation (S-3) |
| 019 | Conditioning silos consisting of three silos controlled by baghouses (S-7, S-8 and S-9) |
| 020 | Screening/distribution system consisting of powdered sugar/starch bins controlled by baghouses (S-5 and S-6) |
| 021 | Alcohol Usage |
| 022 | Sugar packaging line controlled by a baghouse (S-4) |

## CAPACITY AND PERFORMANCE RESTRICTIONS

G.1 Production Restrictions: No more than 2000 tons of refined sugar per day and no more than 730,000 tons of refined sugar per consecutive 12 months shall be packaged at this facility. In addition, no more than 2250 tons of refined sugar per day and no more than 803,000 tons of refined sugar per consecutive 12 months shall be loaded out from this facility. There are no limits on the hours of operation (8760 hours per year) of these emissions units. [Rules 62-210.200 (PTE) and 62-212.400(PSD), F.A.C.; and Permit Nos. PSD-FL-272B and PSD-FL-346A]

G.2 Alcohol Emissions: Alcohol usage from the sugar refinery shall not exceed 30,000 pounds per consecutive 12 months. [Rule 62-212.400(PSD), F.A.C. and Permit No. PSD-FL-272B]

## CONTROL EQUIPMENT AND TECHNIQUES

G.3 Baghouses: The permittee shall operate and maintain high-efficiency baghouses designed to control at least 99.9% of the particulate matter emitted from each emissions unit and point. [Rule 62-212.400(PSD), F.A.C. and Permit No. PSD-FL-272B]

## EMISSION LIMITING STANDARDS

G.4 Baghouse: The following table identifies the PM limits for the baghouses.

| EU No. | Point ID | dscfm | Equivalent Emissions | |
|---|---|---|---|---|
| | | | lb/hour | Ton/Year |
| 015 | S-11 | 110,042 | 1.63 | 7.14 |
| 016 | S-10 | 94,488 | 1.44 | 6.30 |
| 018 | S-1 | 990 | 0.06 | 0.28 |
| | S-2 | 872 | 0.06 | 0.28 |
| | S-3 | 984 | 0.06 | 0.28 |
| 019 | S-7 | 2641 | 0.06 | 0.25 |
| | S-8 | 2641 | 0.06 | 0.25 |
| | S-9 | 2641 | 0.06 | 0.25 |
| 020 | S-5 | 2668 | 0.06 | 0.25 |
| | S-6 | 8735 | 0.19 | 0.82 |
| 022 | S-4 | 9589 | 0.21 | 0.90 |
| Totals | | | 3.89 | 17.0 |

Compliance with the above PM standards is assumed if compliance with the opacity standard is demonstrated. [Rules 62-210.200(PTE), F.A.C. and Permit No. PSD-FL-272B]

G.5 Opacity Standard: As a surrogate for particulate matter, visible emissions shall not exceed 5% opacity from any of these emissions units or points. [Rule 62-212.400(PSD), F.A.C. and Permit No. PSD-FL-272B]

## TESTING

G.6 General Testing Requirements: The unit is subject to the applicable provisions of Appendix C, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

G.7 Test Methods: Any required stack tests shall be performed in accordance with the following methods.

| EPA Method | Description of Method and Comments |
|---|---|
| 1 - 4 | Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}* |
| 5 | Determination of Particulate Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity |

These 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]

G.8 Tests Required: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct visible emissions tests on each baghouse exhaust. Compliance with the PM standards shall be assumed as long as the emission unit remains in compliance with the opacity standard. [Rule 62-297.310(7)(a)1, F.A.C. and Permit No. PSD-FL-272B]

## MONITORING, RECORD KEEPING AND REPORTING

G.9 CAM Plan, Baghouses (EU-018): The permittee shall comply with the following CAM plan.

| CAM Criteria | Indicator #1 |
|---|---|
| Indicator | Opacity of each of baghouse vents (S-1, S-2 and S-3) on the vacuum systems (EU-018) |
| Measurement Approach | In accordance with EPA Method 22, observer conducts a 1-minute observation of each baghouse vent. |
| Indicator Range | An excursion is defined as any observed visible emissions. Excursions trigger inspection, corrective action, record keeping and reporting. |
| Data Representativeness | Visible emissions are either present or not. |
| Verification of Operational Status | Verify operation of vacuum system before observations are made. |
| QA/QC Procedures | EPA Method 22 procedures are specified in Appendix A of 40 CFR 60. |
| Monitoring Frequency | One minute observations made once per day for each baghouse vent. |
| Data Collection Procedures | Daily observations shall be recorded in a log. |
| Averaging Period | NA |

In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. The permittee shall record any problems with operation of the baghouses and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; and 40 CFR 64]

G.10 Monthly Records: Within ten days following each month, the permittee shall calculate the refined sugar packaging rate, the refined sugar load out rate and the alcohol usage rate. The permittee shall record each monthly rate and the 12-month rolling total in a written log. Calculation of the alcohol usage shall be determined by the purchase records and the appropriate Material Data Safety Sheets. [Rule 62-212.400(PSD), F.A.C. and Permit No. PSD-FL-272B]

G.11 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

This subsection addresses the following regulated emissions unit.

| EU No. | Emissions Unit Description |
|---|---|
| 029 | White sugar dryer 2 is a fluidized bed-type dryer/cooler with a rated capacity of 85 tons per hour of refined sugar. After wet refined sugar is centrifuged, the dryer will be used to drive off remaining moisture. Sugar with a moisture content of approximately 1.5% by weight enters the dryer between 120° - 140° F and is suspended in a fluidized bed with jets of hot, conditioned air. A maximum of 11,000 pounds per hour of low pressure steam (12 psig) from the existing mill boilers supply heat for the process; no fuel is fired. Sugar exits the dryer with a moisture content of approximately 0.03% by weight and a temperature between 92° Fto 102° F. The refined sugar is then transferred to the conditioning silos.<br>Particulate matter emissions from the dryer are controlled by a set of four high-efficiency cyclone collectors in parallel followed by a wet scrubber. Flue gas exhaust at 90° F exits a stack approximately 82 feet above ground level with a with a volumetric flow rate of 90,000 acfm. The rectangular stack is 7.0 feet by 6.0 feet. The scrubber pressure drop and scrubber water recirculation flow rate are continuously monitored. |

## CAPACITY AND PERFORMANCE RESTRICTIONS

H.1 Permitted Capacity: The maximum design capacity of the sugar dryer is 85 tons per hour of sugar. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C. and Permit No. PSD-FL-346A]

## CONTROL EQUIPMENT AND TECHNIQUES

H.2 Air Pollution Control Equipment:

a. *Cyclone Collectors*: In accordance with the manufacturer's recommendations, the permittee shall operate and maintain a set of four high-efficiency cyclone collectors in parallel (Entoleter, LLC Model 6600 or equivalent) with a design removal efficiency of at least 99% of the particulate loading from the new white sugar dryer based on the following inlet conditions: inlet temperature of 110° F; inlet flow rate of 105,000 acfm; inlet dust loading of 14 grains per dscf of inlet gas (11,760 lb/hour); and a pressure drop across the cyclone collectors of 6 inches of water column. In accordance with the manufacturer's recommendations, the permittee shall calibrate, operate and maintain a manometer (or equivalent) to monitor the pressure differential across each cyclone collector. Although no periodic records of the pressure differential are required, the devices shall be properly maintained and functional to provide operational data for evaluating problems.

b. *Wet Scrubber*: In accordance with the manufacturer's recommendations, the permittee shall operate and maintain a wet scrubber (Entoleter, LLC Centrifield Vortex Model 1500 or equivalent) with a design removal efficiency of at least 96% of the particulate loading from the new cyclone collectors. The design control efficiency is based on the following inlet conditions: inlet temperature of 113° F; inlet flow rate of 105,000 acfm; inlet dust loading of 0.14 grains per dscf of inlet gas (118 lb/hour); a scrubber water recirculation flow rate of 500 gpm; a scrubber make-up water flow rate of 12 gpm; and a pressure drop of 8 inches of water column. In accordance with the manufacturer's recommendations, the permittee shall calibrate, operate and maintain devices to continuously monitor and record the wet scrubber water recirculation rate (gpm) and the pressure differential across the wet scrubber (inches of water column).

The combined design removal efficiency of the two particulate control devices shall be no less than 99.96% based on the above conditions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and Permit No. PSD-FL-346A]

## EMISSION LIMITING STANDARDS

H.3 PM Standard: As determined by EPA Method 201A stack test, particulate matter emissions less than 10 microns ($PM_{10}$) shall not exceed 0.005 grains per dscf and 4.2 pounds per hour based on the average of three test runs. As determined by EPA Method 5 stack test, particulate matter emissions shall not exceed

15.0 pounds per hour based on the average of three test runs. [Design; Rule 62-212.400(BACT), F.A.C. and Permit No. PSD-FL-346A]

H.4 Opacity Standard: Visible emissions from the wet scrubber stack shall not exceed 10% opacity excluding water vapor. [Rule 62-212.400(PSD), F.A.C. and Permit No. PSD-FL-346A]

**TESTING**

H.5 General Testing Requirements: The emissions unit is subject to the applicable provisions of Appendix C, which specifies the general requirements for test frequencies, test notifications, sampling facilities, test procedures, and test reports. [Rule 62-297.310, F.A.C.]

H.6 Test Methods: If required, stack tests shall be performed in accordance with the following methods or the most recent versions of these methods.

| EPA Method | Description of Method and Comments |
|---|---|
| 1 - 4 | Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}* |
| 5 | Determination of Particulate Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity |
| 201A | Determination of $PM_{10}$ Emissions from Stationary Sources |

These 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]

H.7 Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct compliance tests for opacity. [Rules 62-212.400 (PSD) and 62-297.310(7), F.A.C.; and Permit No. PSD-FL-346A]

H.8 Renewal Compliance Tests: Prior to renewal of the Title V permit, the permittee shall also conduct compliance tests for PM emissions in addition to opacity. [Rules 62-212.400 (PSD) and 62-297.310(7), F.A.C.; and Permit No. PSD-FL-346A]

H.9 Monitoring of Test Parameters: During any required test, the permittee shall monitor and record the following information at the beginning and end of each test run: sugar processing rate through the dryer (tons per hour); the scrubber water recirculation rate (gpm); the scrubber water sugar content in brix; the pressure differential across each cyclone collector (inches of water column); and the pressure differential across the wet scrubber (inches of water column). [Rules 62-4.070(3) and 62-297.310(5), F.A.C. and Permit No. PSD-FL-346A]

**MONITORING, RECORD KEEPING AND REPORTING**

H.10 CAM Plan, Wet Scrubber: The permittee shall comply with the following CAM plan.

| CAM Criteria | Indicator #1 | Indicator #2 |
|---|---|---|
| Indicator | Total scrubber water flow rate | Pressure drop across scrubber |
| Measurement Approach | Flow meter | Manometer (or equivalent) |
| Indicator Range | An excursion is defined as any flow rate **below 500 gallons per minute**. Excursions trigger inspection, corrective action, record keeping and reporting. | An excursion is defined as any pressure drop **below 8 inches of water column**. Excursions trigger inspection, corrective action, record keeping and reporting. |

| CAM Criteria | Indicator #1 | Indicator #2 |
|---|---|---|
| Data Representativeness | Flow meter measures scrubber flow rate with a minimum accuracy of ± 5% of total water flow. | Manometer measures scrubber pressure drop with a minimum accuracy of ± 0.5 inches of water column (gage). |
| Verification of Operational Status | NA | NA |
| QA/QC Procedures | Maintain equipment in accordance with manufacturer's recommendations. | Maintain equipment in accordance with manufacturer's recommendations. |
| Monitoring Frequency | Continuous readout | Continuous readout |
| Data Collection Procedures | Based on continuous monitoring data, calculate and record a 3-hour block average. | Based on continuous monitoring data, calculate and record a 3-hour block average. |
| Averaging Period | 3-hour block average | 3-hour block average |

The scrubber system shall be operated so that fresh water makeup will be added to maintain a maximum sugar content of 15 brix in the recirculated scrubber water. In addition, the permittee shall comply with the general CAM provisions specified in Appendix H of this permit. The permittee shall record any problems with operation of the wet scrubber and corrective actions taken in the Daily Operational Records required by this permit. [Rules 62-204.800 and 62-213.440(1)(b)1.a, F.A.C.; 40 CFR 64; and Permit No. PSD-FL-346A]

H.11 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

## Subsection I. Miscellaneous Material Silos

This subsection addresses the following regulated emissions units.

| EU No. | Emissions Unit Description |
|---|---|
| 010 | Lime silo with baghouse at the water treatment plant |
| 030 | Limestone storage silo with baghouse (IAC Model No. 58TB-BVI-16, style 2) at the molasses plant. Limestone is delivered by truck and unloaded pneumatically into the silo at an approximate rate of 33 tons per hour. Limestone is unloaded from the silo via gravity drop to a mechanical auger that conveys it to the molasses plant. The maximum throughput rate is 5000 tons per year. Particulate matter emissions are estimated as 0.126 lb/hour and 0.55 tons/year. [Permit No. 0510003-033-AC] |
| 031 | Lime storage and truck/rail handling system at the sugar refinery consists of two lime silos, truck and railcar pneumatic unloading and conveying equipment, three associated baghouse control sysems and a lime slaker system (as necessary). Each baghouse control system is designed for a flow rate of approximately 500 acfm and an outlet grain loading of 0.02 grains per dscf. The estimated maximum PM emissions from each baghouse are 0.08 pounds per hour and 0.35 tons per year. [Permit No. 0510003-034-AC] |
| 033 | Salt silo with baghouse (IAC Model No. 58TB-BVI-16:S6) at the molasses plant. The maximum process rate for salt loading is 33 tons/hour and the maximum estimated PM emissions are 0.13 lb/hourand 0.57 tons/year. [Permit No. 0510003-025-AC] |

*Process Description for Lime Storage and Handling System (EU-031)*: A combination of lime and flocculants are used to clarify raw sugarcane juice, which is then evaporated, crystallized, and centrifuged to form raw sugar. Some of the raw sugar is sold and some of it is processed into white sugar at the refinery on site. Lime is delivered by railcar and/or truck and unloaded into two new storage silos. Lime is unloaded from the silos via bottom drop into a lime slaker. Water is mixed with the lime and pumped to a lime slurry storage tank and agitator for use in the process. The total lime throughput is approximately 5000 tons/year.

Lime is unloaded pneumatically from trucks to the silos by a blower system at a rate of approximately 33 tons per hour. A 25-ton truck can be unloaded in about 45 minutes. Lime is unloaded from railcars by a separate vacuum-type system, which includes a collection bin, rotary airlocks, and transporter blower to pneumatically transport lime to the silos at a rate of approximately 5 tons per hour. It can take about 18 hours to unload 180,000 pounds of lime from a railcar. The silos and the collection bin are controlled by a baghouse. The silos are controlled with a bin vent filter to remove particulate matter during silo loading and unloading. Emissions from the collection bin are controlled by a filter receiver to remove particulate matter during railcar unloading. Each baghouse is designed for a flow rate of less than 500 acfm and an outlet grain loading of 0.02 grains per dscf.

### EQUIPMENT

I.1 Equipment: To control PM emissions when loading and unloading, each silo shall be equipped with a baghouse. [Rules 62-4.070(3), 62-210.200(PTE) and F.A.C.]

### PERFORMANCE RESTRICTIONS

I.2 Permitted Capacity:

a. The maximum loading rate for the limestone storage silo (EU 030) is 33 tons/hour. [Permit No. 0510003-033-AC]

b. The maximum operating rate of the salt silo (EU 033) is approximately 33 tons per hour. [Permit No. 0510003-025-AC]

I.3 Restricted Operation: The hours of operation of are not limited (8760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

## EMISSIONS STANDARDS

I.4 Opacity Standards: As determined by EPA method 9, emissions from each baghouse vent shall not exceed 5% opacity. [Rules 62-4.070(3), 62-210.200(PTE), 62-296.320(4)(a) and 62-296.620(4), F.A.C.]

## EMISSIONS PERFORMANCE TESTING

I.5 Compliance Tests: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct visible emissions tests in accordance with EPA Method 9 on each baghouse vent to demonstrate compliance with the opacity standard. The minimum observation period shall be at least 30 minutes or, if the operation is normally completed in less than 30 minutes and does not recur within that time, the test shall last for the length of the silo loading operation. Tests shall be conducted at a material transfer rate representative of the typical operation used throughout the year. For each test, the permittee shall record and report the material handling rate, pneumatic line pressure and pressure differential across the baghouse. For the lime storage and handling system (EU-031), annual tests shall be conducted while unloading lime from a railcar. Prior to renewing the air operation permit, a test shall also be conducted while unloading lime from a truck (EU-031). [Rules 62-4.070(3), 62-296.320(4)(a) and 62-296.620(4), F.A.C.]

## MONITORING, RECORD KEEPING AND REPORTING

I.6 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

## Subsection J. Rental Refinery Package Boiler

This section of the permit addresses the following emissions unit.

| EU No. | Emissions Unit |
|---|---|
| 035 | Rental refinery package boiler with a maximum heat input rate of 12 MMBtu per hour from firing distillate oil |

### EQUIPMENT

J.1 Refinery Package Boiler: In accordance with the conditions of this subsection, the permittee is authorized to install and operate a rental package boiler rated at 300 horsepower that will fire distillate oil. The package boiler will be a rental unit and may be a different unit each year. Depending on the original manufacture date, the selected rental boiler may be subject to the applicable provisions in Subpart Dc of 40 CFR 60. [Permit No. 0510003-045-AC]

### PERFORMANCE RESTRICTIONS

J.2 Permitted Capacity: The maximum heat input rate of the boiler is 12 MMBtu per hour from firing distillate oil at approximately 85 gallons per hour (gph). [Rule 62-210.200(PTE), F.A.C. and Permit No. 0510003-045-AC]

J.3 Authorized Fuel: The boiler is authorized to fire distillate oil or on-specification used oil with a maximum sulfur content of 0.05% by weight. On-specification used oil shall meet the additional requirements specified in Appendix I (Fuel Monitoring) of this permit. [Rule 62-210.200(PTE), F.A.C. and Permit No. 0510003-045-AC]

J.4 Operational Restrictions: The boiler shall only operate during the period of June 1st through September 30th of each year. It shall only operate during this period when all other mill boilers are shutdown (or in the process of shutting down) due to repair or maintenance. The refinery package boiler shall not fire more than 63,240 gallons of distillate oil during the authorized period of operation. [Rule 62-210.200(PTE), F.A.C. and Permit No. 0510003-045-AC]

### EMISSIONS STANDARDS

J.5 Opacity Standard: As determined by EPA method 9, visible emissions shall not exceed 20% opacity except for one six-minute period per hour during which opacity shall not exceed 27%. [Rule 62-296.406, F.A.C.]

J.6 BACT Determinations: Particulate matter and sulfur dioxide emissions shall be minimized by the efficient combustion of distillate oil containing a maximum fuel sulfur content of 0.05% by weight. [Rule 62-296.406, F.A.C.]

### TESTING REQUIREMENTS

J.7 Annual Compliance Tests: During each refinery season (June 1st through September 30th) in which it is operated, the refinery package boiler shall be tested to demonstrate compliance with the visible emissions standard in accordance with EPA Method 9. [Rule 62-297.310(7)(a)4, F.A.C.]

J.8 Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix C (General Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

## MONITORING, RECORD KEEPING AND REPORTING

J.9 Monitoring Equipment: In accordance with the manufacturer's recommendations, the permittee shall install, operate and maintain equipment to continuously monitor the oil flow rate. The device shall be calibrated at least annually and calibration records maintained in a written or electronic log. [Rules 62-4.070(3) and 62-213.440(4), F.A.C.; and Permit No. 0510003-045-AC]

J.10 Fuel Monitoring Requirements: The permittee shall comply with the applicable fuel monitoring requirements specified in Appendix I (Fuel Monitoring) for each authorized fuel. [Rules 62-4.070(3) and 62-210.370(3), F.A.C. and Permit No. 0510003-045-AC]

J.11 Test Notifications, Records and Reports - General Requirements: Appendix C of this permit specifies the general requirements for test notifications, records and reports. [Rule 62-297.310, F.A.C.]

J.12 Notification: Within three days of bringing a rental boiler on site, the permittee shall notify the Compliance Authority of the following: make and model, maximum heat input rate (MMBtu/hour), the applicability of NSPS Subpart Dc, and preliminary plans for conducting a visible emissions test. [Rule 62-4-070(3), F.A.C.]

## OTHER APPLICABLE REQUIREMENTS

J.13 Federal Requirements: If the boiler was originally manufactured, modified or reconstructed after June 9, 1989, it is subject to and shall comply with the applicable federal requirements in NSPS Subpart Dc of 40 CFR 60. The boiler will be a rental unit and may be a different unit each year. See Appendix L (NSPS Provisions) of this permit. [Rule 62-204.800, F.A.C. and Subpart Dc of 40 CFR 60]

**Contents**

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]

*Means*: Title 40, Part 60, Section 7

## GLOSSARY

**° F**: degrees Fahrenheit

**acfm**: actual cubic feet per minute

**ARMS**: Air Resource Management System

**BACT**: best available control technology

**Btu**: British thermal units

**CAM**: compliance assurance monitoring

**CEMS**: continuous emissions monitoring system

**cfm**: cubic feet per minute

**CFR**: Code of Federal Regulations

**CO**: carbon monoxide

**COMS**: continuous opacity monitoring system

**DEP**: Department of Environmental Protection

**Department**: Department of Environmental Protection

**dscfm**: dry standard cubic feet per minute

**EPA**: Environmental Protection Agency

**ESP**: electrostatic precipitator

**EU**: emissions unit

**F.A.C.**: Florida Administrative Code

**F.D.**: forced draft

**F.S.**: Florida Statutes

**FGR**: flue gas recirculation

**Fl**: fluoride

**$ft^2$**: square feet

**$ft^3$**: cubic feet

**gpm**: gallons per minute

**gr**: grains

**HAP**: hazardous air pollutant

**Hg**: mercury

**I.D.**: induced draft

**ID**: identification

**kPa**: kilopascals

**lb**: pound

**MACT**: maximum achievable technology

**MMBtu**: million British thermal units

**MSDS**: material safety data sheets

**MW**: megawatt

**NESHAP**: National Emissions Standards for Hazardous Air Pollutants

**$NO_X$**: nitrogen oxides

**NSPS**: New Source Performance Standards

**O&M**: operation and maintenance

**$O_2$**: oxygen

**Pb**: lead

**PM**: particulate matter

**$PM_{10}$**: particulate matter $\leq$ 10 microns

**PSD**: prevention of signifi9cant deterioration

**psi**: pounds per square inch

**PTE**: potential to emit

**RACT**: reasonably available control technology

**RATA**: relative accuracy test audit

**SAM**: sulfuric acid mist

**scf**: standard cubic feet

**scfm**: standard cubic feet per minute

**SIC**: standard industrial classification code

**SNCR**: selective non-catalytic reduction

**$SO_2$**: sulfur dioxide

**TPH**: tons per hour

**TPY**: tons per year

**UTM**: Universal Transverse Mercator coordinate system

**VE**: visible emissions

**VOC**: volatile organic compounds

## Identification of Primary State and Federal Regulations

### Applicable State Regulations

Emissions units at this facility are subject to the applicable portions of the regulations specified in the following Chapters of the Florida Administrative Code: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and Best Available Control Technology, and Non-attainment Area Review and Lowest Achievable Emission Rate); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). In particular, emissions units are subject to applicable portions of the following source-specific rules.

- Boilers 1, 2, 4, 7 and 8 (EU-001, 002, 009, 014 and 028) are subject to Rule 62-296.410, F.A.C. for carbonaceous fuel burning equipment.
- The temporary rental refinery package boiler is subject to Rule 62-296.406, F.A.C. for fossil fuel steam generators with less than 250 MMBtu per hour of heat input.
- Boilers 4, 7 and 8 (EU-009, 014 and 028), the biomass handling and storage (EU-027) and several emissions units in the sugar refinery (EU-015, 016, 017, 018, 019, 020, 021, 022 and 029) are subject to Rule 62-212.400(BACT), F.A.C.
- For all emissions units requiring tests, Rule 62-297.310, F.A.C. establishes the general requirements.
- The following emissions units are subject to the applicable provisions in Rule 62-213.440, F.A.C. for Compliance Assurance Monitoring: Boilers 1, 2, 4, 7 and 8 (EU-001, 002, 009, 014 and 028), granular carbon regeneration furnace (EU-017), three vacuum pickup systems (EU-018) and white sugar dryer No. 2 (EU-029).

### Applicable Federal Regulations

Federal environmental requirements are established in Title 40 of the Code of Federal Regulations (CFR). Emissions units are subject to the following source-specific regulations.

- All sources subject to a specific NSPS subpart are also subject to the applicable General Provisions in NSPS Subpart A of 40 CFR 60.
- Boilers 7 (EU-014) and 8 (EU-028) are subject to the New Source Performance Standards (NSPS) in Subpart Db of 40 CFR 60 for industrial-commercial-institutional steam generating units with a maximum capacity of more than 100 MMBtu per hour of heat input.
- If the temporary rental refinery package boiler (EU-035) was constructed, modified or reconstructed after June 9, 1989, it is subject to NSPS Subpart Dc of 40 CFR 60 for small industrial-commercial-institutional steam generating units with a maximum capacity of less than 100 MMBtu per hour of heat input, but greater than or equal to 10 MMBtu per hour of heat input.
- The following emissions units are subject to the applicable provisions in 40 CFR 64 for Compliance Assurance Monitoring: Boilers 1, 2, 4, 7 and 8 (EU-001, 002, 009, 014 and 028), granular carbon regeneration furnace (EU-017), three vacuum pickup systems (EU-018) and white sugar dryer 2 (EU-029).

Unless otherwise specified in the permit, the following testing requirements apply as necessary to all emissions units.

**COMPLIANCE TESTING REQUIREMENTS**

1. 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.]

2. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. 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. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

3. 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.]

4. Applicable Test Procedures

   a. *Required Sampling Time.*

      (1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

      (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

         (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

   b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule 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.

TABLE 297.310-1 CALIBRATION SCHEDULE

| ITEM | MINIMUM CALIBRATION FREQUENCY | REFERENCE INSTRUMENT | TOLERANCE |
|---|---|---|---|
| Liquid in glass thermometer | Annually | ASTM Hg in glass ref. thermometer or equivalent or thermometric points | +/-2% |
| Bimetallic thermometer | Quarterly | Calib. liq. in glass | 5° F |
| Thermocouple | Annually | ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer | 5° F |
| Barometer | Monthly | Hg barometer or NOAA station | +/-1% scale |
| Pitot Tube | When required or when damaged | By construction or measurements in wind tunnel D greater than 16" and standard pitot tube | See EPA Method 2, Fig. 2-2 & 2-3 |
| Probe Nozzles | Before each test or when nicked, dented, or corroded | Micrometer | +/- 0.001" mean of at least three readings; Max. deviation between readings, 0.004" |
| Dry Gas Meter and Orifice Meter | 1. Full Scale: When received, when 5% change observed, annually | Spirometer or calibrated wet test or dry gas test meter | 2% |
| | 2. One Point: Semiannually | | |
| | 3. Check after each test series | Comparison check | 5% |

d. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

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

5. 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.]

6. 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. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities*. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities*. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports*.

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms*.

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform*.

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power*.

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of

each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

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

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

(a) Visible emissions, if there is an applicable standard;

(b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

(c) c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. 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.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *Special Compliance Tests*. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it 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.

c. *Waiver of Compliance Test Requirements*. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.]

**RECORDS AND REPORTS**

8. <u>Test Reports</u>:

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

## UNREGULATED EMISSIONS UNIITS

An "unregulated emissions unit" is an emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from otherwise applicable unit-specific emissions or work practice standards (e.g., recordkeeping requirements for small storage tanks under 40 CFR 60, Subpart Kb). All fugitive emissions not subject to unit-specific work practice standards may be included in the application as one or more separate unregulated emissions units. The permittee identifies the following unregulated emissions units and activities for the Clewiston sugar mill and refinery.

* Activities denoted with an asterisk (*) were granted an exemption from air construction permitting by the South District office on February 22, 1996.

**Boiling House**

- Bagacillo cyclones and handling system
- Centrifugals
- Crystallizer cooling towers
- Crystallizers
- Evaporator cleaning operations
- Evaporators
- Handling of raw sugar
- Juice heaters
- Lime storage area (slakers)
- Mud belt presses
- Process tanks including: batch, caustic, chemical neutralization, juice clarified juice, clarifier, condensate, EDTA, flocculants/coagulant mix, flash, hot liming, lime hold tank, mingler, mixer, melter, molasses tanks, mud mixing, mud receiving, pan feed, magma, mud waste muriatic acid, phosphoric acid, slakes lime tank, spent acid, sugar receivers, sulfamic acid, syrup storage and alcohol storage tanks
- Vacuum mud filters and vacuum pumps
- Vacuum pans, receivers and condensers
- Sulfamic acid building (tank, baghouse with hopper, and Rhodine totes)

**Sugar Mill**

- Cane mills
- Cush-cush and DSM screens
- Turbine vents

**Agricultural Equipment Shop**

- Paint booth with filter*

**Miscellaneous Activities**

- Distillate oil storage tanks
- Stationary internal combustion engines (general)
- Emergency generators
- Emergency diesel generator
- Emergency diesel fire pump
- High-service diesel pump
- Propane-fired water heater in railcar wash facility
- Ash handling, loading and storage in boiler house
- Cooling water towers, spray ponds and canals
- Wastewater treatment/cooling towers
- Cane dumping/handling
- Raw and refined sugar handling
- Vacuum cleaning systems
- Cold cleaning operations (non-halogenated solvent)
- Vehicle-generated dust
- Parts washers (non-HAP)
- Boiler feedwater plant
- Painting operations
- Solid/hazardous waste storage area
- Urea storage tank at Boiler 8
- Water treatment plant supply wells ($H_2S$ emissions)

**Molasses Plant**

- Hot water tank heater and fuel tanks ATM, DMX7, mineral mix, mixed feed, urea holding, and urea mixing storage tanks product loading (hoses) in Molasses plant

**SHUTDOWN EMISSIONS UNITS**

The following emissions units have been permanently shut down. Any proposed future operation of these boilers would require a preconstruction review permit as a "new" emissions unit.

| EU No. | Description |
|---|---|
| 003 | Boiler 3: Permanent shutdown required by Permit PSD-FL-333 for PSD netting |
| 004 | Boiler 5: Permanent shutdown required by Permits PSD-FL-208 and PSD-FL-272 for PSD netting |
| 005 | Boiler 6: Permanent shutdown required by Permits PSD-FL-208 and PSD-FL-272 for PSD netting |
| 011 | Lime silo at boiling house |
| 012 | Diesel generator 1: Dismantled and no longer in operation |
| 013 | Diesel generator 2: Dismantled and no longer in operation |
| 023 | Propane sock heaters |
| 032 | Portable rock crusher |

## INSIGNIFICANT EMISSIONS UNITS AND ACTIVITIES

Pursuant to Rule 61-213.430(6)(b), F.A.C., an emissions unit or activity shall be considered insignificant if all of the following criteria are met:

1. Such unit or activity would be subject to no unit-specific applicable requirement.
2. Such unit or activity, in combination with other units and activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s) as defined in subparagraph 62-213.420(3)(c)1., F.A.C., unless it is acknowledged in the permit application that such units or activities would cause the facility to exceed such threshold(s).
3. Such unit or activity would neither emit nor have the potential to emit:
   a. 500 pounds per year or more of lead and lead compounds expressed as lead;
   b. 1,000 pounds per year or more of any hazardous air pollutant;
   c. 2,500 pounds per year or more of total hazardous air pollutants; or
   d. 5.0 tons per year or more of any other regulated pollutant.

Pursuant to Rule 61-213.430(6)(a), F.A.C., all requests for determination of insignificant emissions units or activities made pursuant to paragraph 62-213.420(3)(n), F.A.C., shall be processed in conjunction with the permit, permit renewal or permit revision application submitted pursuant to this chapter. Insignificant emissions units or activities shall be approved by the Department consistent with the provisions of paragraph 62-4.040(1)(b), F.A.C. Emissions units or activities which are added to a Title V source after issuance of a permit under this chapter shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit and also qualify as insignificant pursuant to this rule.

The permittee identifies the following unregulated emissions units and activities for the Clewiston sugar mill and refinery.

**Agricultural Equipment Shop**

- Multiple 55-gallon contaminated diesel drums
- Diesel storage tank
- Low sulfur diesel tank
- Used oil storage tanks (4)
- Gasoline storage tank
- Kerosene storage tank
- Cane burning fuel storage tank
- Various equipment shops
- "Mart Tornado" electric parts cleaner (non-HAP)
- Used antifreeze storage tank

**Cane Fields**

- Agricultural diesel field engines and associated fuel tanks
- Agricultural diesel cane elevator engines and associated fuel tanks

**Miscellaneous Activities**

- Diesel, gasoline and fuel oil storage tanks
- Diesel fuel storage tanks (3)
- Large storage tanks in boiler house
- Used oil tanks/drums (covered)
- Pressurized LPG tanks
- Solvent recovery stills
- Molasses storage tanks
- Acid storage tanks
- Small polymer tanks (2) at water treatment plant
- Ammonia storage tanks
- Process-wide flanges and valves
- Pump vents (lube oil vents)
- Vents from hydraulic/lube oil reservoirs and pumps
- Use of cutting oils
- Painting operations
- Batch mixers (< 30 cu. ft.)
- Containers for oils/wax/grease
- Electric ovens for drying
- Gear boxes, reducers vents
- Kerosene dispenser drip pans

**Insignificant Activities**

- Liquid loading/unloading (non-HAP)
- Oil/water separator/skimmer equipment, troughs/storage
- Scrubber water ponds and troughs
- Metallizing operations
- Wood working and metal working operations
- Locomotive repair shop
- Railroad maintenance
- Sugar warehouses
- Boiler blow-down pipes, vents sandblaster and grinder with filter in powerhouse
- Ash/lime mixing, balanced polymer tanks and chemical storage/mixing tanks for boiler feedwater plant

## Permit History

### Title V Air Operation Permit

The most recent Title V air operation permit for this facility was Permit 0510003-017-AV, which was issued on 10/08/2004. This permit incorporated all previous air construction permits through Permit 0510003-015-AC, which was issued on 03/07/02 to modify the bagasse handling system.

### Air Construction Permits

The following table summarizes the air construction permits issued to this facility.

| Permit No. | Issued | Project Description |
|---|---|---|
| *The following air construction permits were incorporated into previous Permit 0510003-017-AV.* | | |
| AC26-126965 | 02/16/1987 | Boiler 4 |
| AC26-238006 | 02/02/1995 | PSD Permit PSD-FL-208 to construct Boiler 7 |
| AC26-247917 | 05/03/1994 | Construct lime silo |
| AC26-248809 | 08/09/1995 | Boiler 4 |
| AC26-259722 | 02/14/1995 | Miscellaneous |
| 0510003-001-AC | 10/29/1996 | Construct sugar refinery; superseded by Permit 0510003-004-AC |
| 0510003-003-AC | N/A | Withdrawn |
| 0510003-004-AC | 02/14/1997 | Modification to sugar refinery; superseded by Permit PSD-FL-272A |
| 0510003-005-AC | 10/31/1997 | Minor permit revision to extend testing for Boiler 7 |
| 0510003-006-AC | 11/14/1997 | Minor permit revision to establish testing protocol for Boiler 7 |
| 0510003-007-AC | 03/22/1999 | Minor permit revision for Boiler 4 |
| 0510003-008-AC | 06/14/1999 | Minor revision for sugar mill log |
| 0510003-009-AC | 11/19/1999 | PSD Permit PSD-FL-272 to modify Boiler 4, Part I; superseded by PSD-FL-272A |
| 0510003-010-AC | 03/08/2001 | PSD Permit PSD-FL-272A to modify Boiler 4, Part II |
| 0510003-011-AC | 06/12/2000 | Construct new bagasse handling system; superseded by Permit 0510003-015-AC |
| 0510003-012-AC | 02/20/2001 | Administrative correction |
| 0510003-015-AC | 03/07/2002 | Modify bagasse handling system; superseded by Permit PSD-FL-333 |
| *In addition to the previous air construction permits, the following air construction permits were incorporated into renewal Permit 0510003-032-AV.* | | |
| 0510003-016-AC | N/A | Withdrawn |
| 0510003-018-AC | 06/06/2003 | Burner modifications to Boilers 4 and 7 to fire distillate oil; superseded by Permit 0510003-029-AC |
| 0510003-019-AC | N/A | Withdrawn |
| 0510003-020-AC | 01/15/2003 | Modification for alternate steam conditions for Boiler 3; Boiler 3 is permanently shutdown |
| 0510003-021-AC | 11/21/2003 | PSD Permit PSD-FL-333 to construct Boiler 8; superseded by PSD-FL-333A |
| 0510003-022-AC | 06/03/2003 | Off season repairs for Boilers 1 – 7; only incorporate off-season record keeping and reporting requirements |
| 0510003-023-AC | N/A | Withdrawn |
| 0510003-024-AC | 11/04/2004 | Revision to Boiler 8 (PSD-FL-333A) for shakedown and DAF material; superseded by Permit PSD-FL-333B |

**Permit History**

| Permit No. | Issued | Project Description |
|---|---|---|
| 0510003-025-AC | 12/21/2004 | Construct salt silo for molasses plant |
| 0510003-026-AC | 02/01/2005 | PSD Permit PSD-FL-346 to construct new white sugar dryer 2; superseded by Permit 0510003-038-AC |
| 0510003-027-AC | 02/24/2005 | Burner modifications for Boilers 1 and 2 to fire distillate oil; superseded by Permit 0510003-036-AC |
| 0510003-028-AC | N/A | Exempt |
| 0510003-029-AC | 04/01/2005 | Revision to extend burner modifications to Boiler 4; superseded by Permit 0510003-039-AC for Boiler 4 |
| 0510003-030-AC | 04/07/2006 | PSD revision (PSD-FL-333B) for Boiler 8 to add final NEHSAP DDDDD provisions; superseded by Permit PSD-FL-333C |
| 0510003-031-AC | (Pending) | Miscellaneous air construction permit revisions issued concurrent with Title V Permit 0510003-032-AV |
| 0510003-033-AC | 09/06/2005 | Construct limestone silo |
| 0510003-034-AC | 01/20/06 | Construct new lime storage and handling system |
| 0510003-035-AC | 06/19/2006 | Addition of cyclone dust collector to Boiler 8; superseded by Permit PSD-FL-333C |
| 0510003-036-AC | 08/02/2006 | Revision to burner modifications for Boilers 1 and 2; superseded by Permit 0510003-039-AC |
| 0510003-037-AC | 03/30/07 | PSD revision (PSD-FL-333C) for Boiler 8 to increase heat input rate and modify bagasse handling system |
| 0510003-038-AC | 12/22/2006 | Revision for white sugar dryer 2 to change PM standard; supersedes Permit 0510003-021-AC |
| 0510003-039-AC | 09/20/2006 | Revision of oil firing systems for Boilers 1, 2 and 4; supersedes Permits 0510003-018-AC and 0510003-027-AC |
| 0510003-040-AC | N/A | Withdrawn |
| 0510003-041-AC | N/A | Withdrawn |
| 0510003-043-AC | N/A | Exempt |
| 0510003-044-AC | 12/06/2007 | Boiler 7 wood chip firing |
| 0510003-045-AC | 06/12/2008 | Temporary refinery package boiler |
| 0510003-046-AC | 12/30/2009 | Letter of authorization for alternate method of monitoring flue gas moisture content |

## Fugitive Dust Precautions

The Clewiston sugar mill and refinery includes the following industrial activities that may generate fugitive dust emissions: sugarcane loading, unloading and handling; bagasse and wood storage and handling; boiler ash removal, storage and handling; vehicular traffic on paved and unpaved roads; the use of bagged, dry chemicals; miscellaneous outdoor painting; and construction, demolition or wrecking. Unless otherwise specified by this permit, the permittee shall take reasonable precautions to prevent the emissions of unconfined particulate matter from these and other similar activities, including:

- Using covered conveyors on the carbonaceous fuel handling systems;
- Using enclosed material transfer points where feasible;
- Minimizing the distance carbonaceous fuel is dropped during handling;
- Using windbreaks around the material handling equipment and storage piles;
- Using enclosures and curtains to reduce fugitive particulate matter emissions from painting operations;
- Using water to control dust from boiler ash handling;
- Applying water or approved dust suppressants to unpaved roads, yards, uncovered storage piles, and similar activities. Unless necessary to mitigate fire hazards or for other safety concerns, water should not be applied to bagasse or wood storage piles because these materials are used for boiler fuels;
- Applying water or approved dust suppressants to control dust from activities such as the demolition of buildings, grading roads, construction and land clearing;
- Maintenance and sweeping of paved areas to prevent re-entrainment; and
- Landscaping or planting of vegetation.

Fugitive dust may not be a concern at all times. A variety of factors may exacerbate fugitive dust emissions such as dry weather, high winds, temporarily increased activities, construction-related activities, etc. Therefore, the permittee shall take the above reasonable precautions as necessary to prevent and minimize fugitive dust emissions.

[Rules 62-4.070(3) and 62-296.320(4)(c)2, F.A.C.]

## Compliance Assurance Monitoring Plan, General Provisions

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1-17 are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables.

**40 CFR 64.6 Approval of Monitoring**

1. Plans: The attached CAM plans are approved for the purposes of satisfying the requirements of 40 CFR 64.3. [40 CFR 64.6(a)]

2. Contents: The attached CAM plans include the following information:

   a. The indicators to be monitored (such as temperature, pressure drop, emissions, or similar parameter);

   b. The means or device to be used to measure the indicators (such as temperature measurement device, visual observation, or CEMS); and

   c. The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.

   [40 CFR 64.6(c)(1)]

3. Excursions: The attached CAM plans describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to and reporting exceedances or excursions. [40 CFR 64.6(c)(2)]

4. Required Monitoring: The permittee is required to conduct the monitoring specified in the CAM plan and shall fulfill the obligations specified in the CAM plan. [40 CFR 64.6(c)(3)]

**40 CFR 64.7 Operation of Approved Monitoring**

5. Commencement of Operation: The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit. [40 CFR 64.7(a)]

6. Proper Maintenance: At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment. [40 CFR 64.7(b)]

7. Continued Operation: Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR 64.7(c)]

8. Response to Excursions or Exceedances:

   a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

   b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) and (2)]

9. Documentation of Need for Improved Monitoring: If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR 64.7(e)]

**40 CFR 64.8 Quality Improvement Plan (QIP) Requirements**

10. Triggering a QIP: Based on a determination that the owner or operator has not used acceptable procedures in response to an excursion or exceedance, the permitting authority may require the owner or operator to develop and implement a QIP. An accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices. [40 CFR 64.8(a)]

11. Elements of a QIP:

    a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

    b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

        (1) Improved preventive maintenance practices.

        (2) Process operation changes.

        (3) Appropriate improvements to control methods.

        (4) Other steps appropriate to correct control performance.

        (5) More frequent or improved monitoring (only in conjunction with one or more of these steps).

    [40 CFR 64.8(b)]

12. QIP Notification: If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined. [40 CFR 64.8(c)]

13. Revised QIP: Following implementation of a QIP, upon any subsequent determination that the owner or operator has not used acceptable procedures in response to an excursion or exceedance, the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

    a. Failed to address the cause of the control device performance problems; or

    b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

    [40 CFR 64.8(d)]

14. Compliance and QIP Implementation: Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or

recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. [40 CFR 64.8(e)]

**40 CFR 64.9 Reporting And Recordkeeping Requirements**

15. General Reporting Requirements:

    a. Commencing from the effective date of this permit, the owner or operator shall submit monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.

    b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:

        (1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

        (2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

        (3) A description of the actions taken to implement a QIP during the reporting period. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

    [40 CFR 64.9(a)]

16. General Recordkeeping Requirements:

    a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

    b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

    [40 CFR 64.9(b)]

**40 CFR 64.10 Savings Provisions**

17. Savings Provisions: It should be noted that nothing in this appendix shall:

    a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

    b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

    c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

    [40 CFR 64.10]

## Fuel Monitoring

The following conditions specify the applicable requirements for sampling and analyzing the authorized fuels at these facilities. These are enforceable conditions of the permit.

### BAGASSE

Bagasse is fired in the boilers to provide process steam and heat for the sugar mill and refinery. Bagasse is the fibrous byproduct remaining from sugarcane after the juice is extracted in the milling process. Typically, the bagasse has a moisture content of 49% to 55% by weight, a maximum sulfur content of 0.03% to 0.07% by weight and a heating value of approximately 3600 Btu per pound of wet bagasse. Bagasse is stored on site in large, uncovered stockpiles.

1. Bagasse - Sampling and Analysis: A representative sample of bagasse shall be taken during each calendar quarter bagasse is fired and analyzed for the following: heating value (Btu/lb, as fired and dry); moisture content (percent by weight); sulfur content (percent by weight, as fired and dry); and ash content (percent by weight, as fired and dry). If no bagasse was fired during a quarter, the report shall indicate that no bagasse was fired as boiler fuel during the given quarter. Records of the results of these analyses shall be maintained on site and made available upon request. [Permit No. PSD-FL-333C]
2. Bagasse Firing Records: For the Annual Operating Report, the permittee shall calculate and record the annual bagasse firing rate. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

### WOOD CHIPS

Boilers 7 and 8 are authorized to fire wood chips as an auxiliary fuel to supplement bagasse. In general, wood chips would be commingled and fired with bagasse to extend bagasse through the refinery season. Typically, the wood chips have a moisture content of 38% to 40%, a maximum sulfur content of 0.05% by weight, and a heating value of approximately 4070 Btu per pounds of wet wood. Wood chips are generally sized to 3" or less and stored in large, uncovered stockpiles.

3. Wood Chips - Sampling and Analysis: A representative sample of wood chips shall be taken during each calendar quarter wood chips are fired and analyzed for the following: heating value (Btu/lb, as fired and dry); moisture content (percent by weight); sulfur content (percent by weight, as fired and dry); and ash content (percent by weight, as fired and dry). Records of the results of these analyses shall be maintained on site and made available upon request. If no wood chips were fired during a quarter, the report shall indicate that no wood chips were fired as boiler fuel during the given quarter. Analytical results shall be determined and available for review within 30 days of the end of each calendar quarter. [Permits PSD-FL-333C and PSD-FL-389]
4. Wood Chips Firing Records: For each delivery of wood chips to the storage area, the permittee shall log the amount of wood chips delivered. For the Annual Operating Report, the permittee shall calculate the annual wood chips firing rate based on the difference between the total wood chips delivered and the amount of wood chips remaining. The total annual heat input rate from firing wood chips shall be calculated based on the annual firing rate and the measured heating values as determined from the sampling and analyses conducted throughout the year. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

### DISTILLATE OIL

Combustion units at these facilities include the mill boilers, the rental refinery boiler and the afterburner for the granular carbon regenerative furnace. Permitted units may only fire distillate oil with a maximum sulfur content of 0.05% by weight.

5. Distillate Oil Sampling and Analyses:
   a. For each oil delivery, the permittee shall maintain records of: the date, the gallons delivered, and a certified fuel oil analysis from the vendor including the heating value (Btu/lb), density (pounds/gallon) and sulfur content (percent by weight).
   b. The following methods are approved analytical methods for determining these characteristics: ASTM Method D-129, ASTM D-1552, ASTM D-2622, and ASTM D-4294. Other equivalent ASTM methods or Department-approved methods are also acceptable.
   c. At least once during each federal fiscal year, the permittee shall have a representative sample taken from each oil storage tank and analyzed in accordance with the authorized methods. Results of the analysis shall be submitted to the Compliance Authority within 45 days of sampling.

[Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.; and Permits 0510003-018-AC, 0510003-039-AC and PSD-FL-333C]

6. Distillate Oil Firing Records: Within three working days following each month, the permittee shall observe the integrator on the oil flow meter of each combustion unit and record the amount oil fired for the previous month. To determine compliance with oil firing restrictions and caps, the permittee shall also calculate and record the 12-month rolling total oil firing rate. When requested by the Department or Compliance Authority, these records shall be available within 3 days of such request. This information shall also be used for the Annual Operating Report. The total annual heat input rate from oil firing shall be calculated based on the annual firing rate and the measured heating values as determined from the sampling and analyses conducted throughout the year. [Rules 62-4.070(3) and 62-213.440(1)(b)1.b, F.A.C.]

**INCIDENTAL AMOUNTS OF ON-SPECIFICATION USED OIL FUEL**

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

7. On-Spec Used Oil Firing:

   a. The permittee may fire incidental amounts of bagasse/on-specification oil with other authorized fuels in any of the mill boilers. To the extent practicable, the bagasse/on-specification oil shall be commingled with bagasse and/or wood chips in the existing conveyor system and distributed among the operational boilers. [Rule 62-4.070, F.A.C. and Permit PSD-FL-333C]

   b. The permittee may fire on-specification used oil generated on site in the temporary rental refinery package boiler.

8. On-Spec Used Oil Specifications: Incidental amounts of used oil to be fired in the boilers shall be on-specification used oil generated on site at this facility. The permittee shall maintain records sufficient to document that the used oil meets the following requirements:

   a. Only "on-specification" used oil containing a polychlorinated biphenyls (PCB) concentration of less than 50 ppm shall be fired at this facility.

   b. The used oil shall meet the following EPA specifications for "on-specification used oil" in Subpart B of 40 CFR 279:

| Constituent/Property | Allowable Level |
|---|---|
| Arsenic | 5.0 ppm, maximum |
| Cadmium | 2.0 ppm, maximum |
| Chromium | 10.0 ppm, maximum |
| Lead | 100.0 ppm, maximum |
| Total Halogens | 1000.0 ppm, maximum |
| Flash point | 100° F, minimum |

   Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil. The firing of off-specification used oil at this facility is prohibited.

   c. On-specification used oil with a PCB concentration of 2 ppm to less than 50 ppm shall be fired only at normal unit operating temperatures and shall not be fired during periods of startup or shutdown.

   d. On-specification used oil with a PCB concentration of 2 ppm or less may be fired at any time.

   e. On-specification used oil shall meet the maximum sulfur content specified in the permit.

   [Rule 62-4.070, F.A.C.; Subpart B, 40 CFR 279; and Permit PSD-FL-333C and Permit 0510003-045-AC]

9. <u>On-Spec Used Oil Records</u>: The permittee shall keep records sufficient to document compliance with the above requirements. The records shall be made available when requested by the Compliance Authority. Annual usage of on-specification used oil shall be reported in the Annual Operating Report. [Rule 62-4.070, F.A.C. and Permit PSD-FL-333C and Permit 0510003-045-AC]

## Good Combustion Practices for All Boilers

### Purpose

The purpose of this plan is to summarize the operational, maintenance and monitoring procedures that will promote good combustion in the sugar mill boilers. Careful attention to the mixing of fuel and combustion air will result in efficient combustion and minimize CO, PM and VOC emissions while optimizing $NO_X$ emissions. Adequate maintenance will promote effective combustion and ensure reliable operation throughout the crop season. See the permit subsections for other specific requirements regarding good combustion practices.

### Training

Power plant operators are certified by the National Institute for the Uniform Licensing of Power Engineers (NIULPE) as 4th Class Engineers or better. The rate of pay is based on a sliding scale that encourages higher certification up to 1st Class Engineer. Other training requirements accompany this outside certification including all aspects of good combustion practices as well as the proper operation of the boiler and control equipment to minimize emissions.

### Requirements

1. Maintenance and Repair Activities: Off season routine maintenance activities are intended to maintain the boilers at current operational levels and reliability for the upcoming cane milling seasons. Replacements shall be made with "functionally equivalent" components that serve the same purpose as the component being replaced. Routine maintenance activities shall not increase the capacity of any boiler or change the basic design parameters including fuel firing rates or heat input rates. In addition, such activities shall not increase the emission rates of any boiler or the cane milling capacity of the plant. The permittee shall consult well in advance with the Department regarding any unusually large, expensive or infrequent maintenance efforts that may not be considered routine. [Permit 0510003-022-AC]
2. Maintenance Summary Report: Within 60 days of beginning the crop season, the permittee shall submit a report to the Department's Bureau of Air Regulation and the Complaince Authority that summarizes the following information: a general description of the routine maintenance and repair work performed on each boiler during the previous off season; a summary of the off season maintenance inspections; and a revised schedule of routine maintenance and repair activities for the next off season based on the recent inspections and schedule. [Permit 0510003-022-AC]
3. Off Season Preparations: Before each crop season, the permittee shall conduct the following activities as necessary to ensure proper operation of the boilers and control equipment.
    - Inspect, clean and repair the boiler, air ductwork, air heaters, wet scrubbers, cyclones and electrostatic precipitators.
    - Inspect and repair damaged refractory and boiler casing.
    - Inspect and remove loose scale, sand and other debris from the outer surfaces of the boiler and tubes.
    - Inspect and clean settling chambers in the furnace, breeching and heat traps, where cinders can accumulate.
    - Inspect, clean and repair boiler grates to ensure proper mechanical operation and maintain open air holes.
    - Inspect, repair and adjust the combustion control settings and linkages to fuel feeders, forced-draft fan and over-fire air fan.
    - Inspect, clean and repair all oil burners and related oil piping, atomizing steam and air registers.
    - Inspect, clean and repair all fans, blades and motors.
    - Inspect and repair all pumps and pump drives.
    - Identify the proper skirt level of each wet impingement scrubber and mark a permanent reference on the outside.
    - Inspect, calibrate and repair all instruments for boiler operation and control, including the oxygen and carbon monoxide process monitors. Record in repair log at the instrument shop.
4. Operational Practices: The permittee shall employ the following practices to promote good combustion.
    - To the extent practicable, maintain the bagasse moisture content at 55% by weight or less.

- To the extent practicable, maintain fuel and excess air in the proper proportion to promote good combustion and minimize smoke.
- As necessary, remove ash present in the ash pits to minimize any furnace draft upsets.
- For boilers with stacks monitored by closed circuit television, view the stack video monitor at least once per hour to visually confirm that good combustion is occurring. If an abnormal plume is observed, take corrective actions.
- Several times per shift, examine the boiler grates and feeders for proper distribution and adjust operations as necessary.
- Once per shift, inspect and clean burners if needed.
- Once per day, conduct a walk-around inspection of the boiler area and check the following: fans, pumps, casings, ductwork, scrubbers and ESP. Repair as needed and in coordination with the production schedule.

5. Outage Inspections and Repair: During an outage, the permittee shall conduct the following activities.

- When the furnace has cooled, inspect the interior components of the fuel grates. As necessary, remove slag or other obstructions to the openings of the grates.
- Inspect the boiler periodically for any air leaks that may have developed between the grates and walls of the boiler. Repair as needed.
- As operating experience dictates for the stoker boilers, stop the stoker and forced draft fan and clean out the siftings chambers. After the siftings chambers have been cleaned, tightly close and seal all access doors and ash pit doors to minimize air leakage.
- At regular intervals, inspect all air swept fuel distributor spout joints and between spout and mounting plate for air leaks. Repair as necessary.
- At regular intervals, inspect the air supply duct, damper housing and fuel distributor spouts for air leaks. Repair as necessary.

## Startup, Shutdown and Malfunction Plans for Boilers

### General Training

All operators and supervisors shall be properly trained to operate and maintain the boilers as well as the pollution control and monitoring equipment in accordance with the guidelines and procedures established by the manufacturer and permit. The training shall include good operating practices as well as methods of minimizing excess emissions during startups, shutdowns, and malfunctions. [Rule 62-210.700(1), F.A.C.]

### Boilers 1 and 2

Cold Startup

1. Start the feedwater pump and check for proper lubrication and vibration.
2. Fill the scrubber to the proper starting level and set the delta P controller to "+8".
3. Open the spray nozzles in the scrubber and start water flow to the scrubber.
4. Align fuel, gas and air atomization lines.
5. Start the fuel pump and burner sequence.
6. As the boiler heats up, adjust the scrubber delta P as needed to maintain proper amps.
7. Start the distributor and over fire fan. Once equipment is properly operating, adjust over fire fan, forced draft fan, and under-grate air to 50%. Start feeding bagasse.
8. Once fire is established, start all slurry water, grates and adjust all dampers as needed.
9. Continue to observe the stack plume, the scrubber water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain optimum operating conditions.
10. Normally, a cold startup will require 6 to 12 hours from the first fire to normal working pressure.

Warm Startup

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on water valves to scrubber spray nozzles to start scrubber.
3. Check the boiler and scrubber water levels, circulating pump and spray nozzles, and make sure they are functioning properly.
4. Light a burner and continue to observe the stack plume, water levels, and burners.
5. As the carbonaceous fuel fire gets hot enough to meet steam demand, reduce the burner fuel until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
6. Continue to observe the stack plume, scrubber water level, and carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain optimum operating conditions.
7. Normally, a warm startup requires 1 to 5 hours, depending on boiler operating conditions.

Shutdown

1. Slowly reduce the feeders until boiler is offline. Once boiler is offline, stop the feeders.
2. After all bagasse has burned out of the furnace, stop the over-fire air fans, stop the distributor air fans, and adjust the over-fire air to 50%.
3. The scrubber is turned off after the fire in the boiler is extinguished.
4. When the furnace temperature reaches 250° F, stop the forced draft fan, adjust the damper and under-grate damper to 50% and then stop the induced draft fan.

**Boiler 4**

Cold Startup

1. Start the feedwater pump and check for proper lubrication and vibration.
2. Fill the scrubber to the proper starting level and set the delta P controller to "+8".
3. Open the spray nozzles in the scrubber and start water flow to the scrubber.
4. Align fuel, gas and air atomization lines.
5. Start the fuel pump and burner sequence.
6. As the boiler heats up, adjust the scrubber delta P as needed to maintain proper amps.
7. Start the distributor and over fire fan. Once equipment is properly operating, adjust over fire fan, forced draft fan, and under-grate air to 50%. Start feeding bagasse.
8. Once fire is established, start all slurry water, grates and adjust all dampers as needed.
9. Continue to observe the stack plume, the scrubber water level, and the carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain optimum operating conditions.
10. A cold startup is a startup after the boiler has been down for more than 4 or 5 hours. Typically, a cold startup will require 6 to 12 hours from the first fire to normal working pressure. There may be 10 cold startups per crop season (more or less) depending on excessive rain and mechanical breakdowns.

Warm Startup

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on water valves to scrubber spray nozzles to start scrubber.
3. Check the boiler and scrubber water levels, circulating pump and spray nozzles, and make sure they are functioning properly.
4. 2Light a burner. Continue to observe the stack plume, water levels, and burners.
5. As the carbonaceous fuel fire gets hot enough to meet demand, reduce the burner fuel until it can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
6. Continue to observe the stack plume, scrubber water level, and carbonaceous fuel level, making adjustments to drafts, fuel, and scrubber to maintain the optimum operating conditions.
7. A warm startup is a startup after the boiler has been down for less than 5 hours. Usually, the longer the boiler is down means a longer period will be needed for warm startup. Typically, a warm startup requires 1 to 5 hours depending on boiler operating conditions. There may be 5 warm startups per crop season (more or less) depending on mechanical breakdowns and mill interruptions.

Shutdown

1. Slowly reduce the feeders until boiler is offline. Once boiler is offline, stop the feeders.
2. After all bagasse has burned out of the furnace, stop the over-fire air fans, stop the distributor air fans, and adjust the over-fire air to 50%.
3. The scrubber is turned off after the fire in the boiler is extinguished.
4. When the furance temperature reaches 250° F, stop the forced draft fan, adjust the damper and under-grate damper to 50% and then stop the induced draft fan.

**Boiler 7**

Cold Startup

1. Start the feedwater pump and check for proper lubrication and vibration.

2. Align fuel, gas and air atomization lines.
3. Start the fuel pump and burner sequence.
4. Start the slurry water, skakers, submerged ash belt, electrostatic precipitator scrolls and adjust dampers as needed.
5. Start the over fire fan and once properly operating, adjust over fire fan, forced draft fan, and under-grate air. Start feeding bagasse.
6. Set up the cyclone sand separators, spray nozzles and pumps.
7. When the electrostatic precipitator meets all interlocks (oxygen level, temperature and ash scrolls), start all three fields.
8. Normally, a cold startup will require 6 to 12 hours from the first fire to normal working pressure.

Warm Startup (approximately 1 to 5 hours)

1. This type of startup is applicable when the boiler has been shutdown for a short period of time and is still hot.
2. Turn on wet sand separator.
3. Check the boiler and wet sand separator water level, and circulating pump and make sure they are functioning properly.
4. Light a burner, continue to observe the stack plume, water levels, and burners.
5. Activate electrostatic precipitator.
6. Feed carbonaceous fuel from the mill to the boiler slowly at first. As the furnace gets hotter and the carbonaceous fuel is burning better, decrease fuel oil until burners can be turned off. As the carbonaceous fuel fire gets hot enough to meet steam demand, reduce the fuel oil until the burners can be turned off. Adjust the dampers to get optimum carbonaceous fuel firing.
7. Continue to observe the stack plume, wet sand separator water level, and carbonaceous fuel level, making adjustments to drafts, fuel, wet sand separator and ESP to maintain optimum operating conditions.
8. Normally, a warm startup requires 1 to 5 hours, depending on boiler operating conditions.

Shutdown

1. Slowly reduce the feeders until boiler is offline. Once boiler is offline, stop the feeders.
2. After all bagasse has burned out of the furnace, stop the over-fire air fans, stop the distributor air fans.
3. Deactivate the electrostatic precipitator and turn off the wet sand separator.

**Boiler 8**

Startup

1. Align compressed air system and air compressors for Boiler 8 plant air and instrument air.
2. Align and start instrument air dryer.
3. Start canal water pump for wet cyclone collectors.
4. Start slurry pump.
5. Start electrostatic precipitator ash mix tank.
6. Start electrostatic precipitator hopper screw conveyors.
7. Start electrostatic precipitator purge air blowers.
8. Set up air dampers to start induced draft air fan.
9. Start induced draft air fan, over-fire air fan and distributor air fan.

10. Start an oil pump.
11. Start the desired oil burner.
12. While boiler is heating up, start the bagasse conveyors for Boiler 8 and fill bagasse feeders.
13. When the boiler pressure gets above 500 psig, start introducing bagasse into the boiler.
14. Start the five electrostatic precipitator transformer-rectifiers.
15. Start the selective non-catalytic reduction system.
16. It will take approximately 4 to 5 hours to warm up the boiler, reach the minimum boiler temperature and begin firing biomass. Once biomass firing begins, the full steaming rate can be achieved in approximately 30 to 60 minutes.

Shutdown

1. Reduce boiler load to minimum.
2. Allow bagasse feeders to run empty.
3. When the fire is completely out, stop the distributor air fan.
4. Stop the over-fire air fan.
5. Turn off the electrostatic precipitator fields.
6. Turn off the selective non-catalytic reduction system.
7. Stop the grate drives.
8. Stop the primary air fans.
9. Stop the induced draft fan.
10. Shutdown the canal water pump.

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 biomass is fired.

NOx Controls

When the SNCR manufacturer's minimum operating temperature requirement is met, the SNCR system will be activated for $NO_X$ 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 $NO_X$ standard based on the current urea injection rate, boiler load, furnace temperature, and $NO_X$ emissions. During shutdown, the SNCR system shall remain operational until the operating temperature drops below the minimum requirement.

As indicated, the following emissions units are subject to applicable New Source Performance Standards (NSPS) in Subparts A, Db or Dc of 40 CFR 60 and adopted by reference in Rule 62-204.800(8), F.A.C.

| EU No. | Description |
|---|---|
| NSPS Subparts A (General Provisions) and Db (Industrial-Commercial-Institutional Steam Generating Units) | |
| 014 | Boiler 7 |
| 028 | Boiler 8 |
| NSPS Subparts A (General Provisions) and Dc (Small Industrial-Commercial-Institutional Steam Generating Units) | |
| 035 | Rental Refinery Package Boiler |

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.

**SUBPART A-GENERAL PROVISIONS**

**40 CFR 60.1 Applicability.**

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution controlagency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).

**40 CFR 60.5 Determination of construction or modification.**

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

**§ 60.6 Review of plans.**

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

**40 CFR 60.7 Notification and record keeping.**

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) Reserved.

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

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

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

(6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

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

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

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

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

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

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

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

Company: ______________________________

Address: ______________________________

Process Unit(s) Description: ______________________________

Emission Limitation: ______________________________

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

Reporting Period Dates: From ____________ to ____________

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

Monitor Manufacturer: ______________________________

Monitor Model No.: ______________________________

Date of Latest CMS Certification or Audit: ____________

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

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

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

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

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

*Name*: ______________________________

*Signature*: ______________________________

*Title*: ______________________________

*Date*: ____________

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

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

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

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

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

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance re-port (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

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

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

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).
(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

**40 CFR 60.8 Performance tests.**

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems , etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the perfomance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:
(1) Sampling ports adequate for test methods applicable to such facility. This includes
(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable

standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally
lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

**§ 60.9 Availability of information.**

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

**40 CFR 60.10 State authority.**

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:
(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

**40 CFR 60.11 Compliance with standards and maintenance requirements.**

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

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

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.

(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the

Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.

**40 CFR 60.12 Circumvention.**

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

**40 CFR 60.13 Monitoring requirements.**

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuos opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d) (1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure.The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g)(1) When more than one continuous monitoring system is used to measure the emissions from only one affected facility (e.g. multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless installation of fewer systems is approved by the Administrator.

(2) When the effluents from two or more affected facilities subject to the same opacity standard are combined before being released to the atmosphere, the owner or operator may either install a continuous opacity monitoring system at a location monitoring the combined effluent or install an opacity combiner system comprised of opacity and flow monitoring systems on each stream, and shall report as per Sec. 60.7(c) on the combined effluent. When the affected facilities are not subject to the same opacity standard applicable, except for documented periods of shutdown of the affected facility, subject to the most stringent opacity standard shall apply

(3) When the effluents from two or more affected facilities subject to the same emissions standard, other than opacity, are combined before released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the continuous monitoring standard, separate continuous monitoring systems shall be installed on each effluent and the owner or operator shall report as required for each affected facility.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners or operators complying with the requirements in Sec. 60.7(f)(1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng or pollutant per J of heat input). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in section 8.4 of Performance Specification 2 and substitute the procedures in section 16.0 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.45(g)(3), 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in section 8.4 of Performance Specification 2.

**40 CFR 60.14 Modification.**

(a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally
beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j) (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

**40 CFR 60.15 Reconstruction.**

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost"' means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

**§ 60.18 General control device requirements.**

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c) (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i) (A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, Vmax, as determined by the following equation:

$V_{max}=(X_{H2}-K_1)*K_2$

Where:

$V_{max}$=Maximum permitted velocity, m/sec.

$K_1$=Constant, 6.0 volume-percent hydrogen.

$K_2$=Constant, 3.9(m/sec)/volume-percent hydrogen.

$X_{H2}$=The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, Vmax, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, Vmax, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f) (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i \qquad \text{Eq. 1}$$

where:

HT=Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}}\right) \left(\frac{\text{g mole}}{\text{scm}}\right) \left(\frac{\text{MJ}}{\text{kcal}}\right)$$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}}\right)$ is 20°C;

Eq. 2

Ci=Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

Hi=Net heat of combustion of sample component i, kcal/g mole at 25 °>C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, Vmax, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation. Log10 (Vmax)=(HT+28.8)/31.7

Vmax=Maximum permitted velocity, M/sec

28.8=Constant

31.7=Constant

HT=The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, Vmax, for air-assisted flares shall be determined by the following equation.

Vmax=8.706+0.7084 (HT)

Vmax=Maximum permitted velocity, m/sec

8.706=Constant

0.7084=Constant

HT=The net heating value as determined in paragraph (f)(3).

**§ 60.19 General notification and reporting requirements.**

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word ''calendar'' is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the post-mark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

## 40 CFR PART 60, SUBPART Db - STANDARDS OF PERFORMANCE INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

### § 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 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides ($NO_X$) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and $NO_X$ standards under this subpart and to the sulfur dioxide ($SO_2$) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the $NO_X$ standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the $NO_X$ standards under this subpart and the PM and $SO_2$ standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and $NO_X$ standards under this subpart and the $SO_2$ standards under subpart J (§60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the $NO_X$ and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(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).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

**§ 60.41b Definitions.**

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

*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 8,760 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.

*Byproduct/waste* means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide ($CO_2$) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

*Chemical manufacturing plants* mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

*Coal refuse* means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

*Cogeneration* , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

*Coke oven gas* means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

*Combined cycle system* means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

*Conventional technology* means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization 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 (incorporated by reference, see §60.17).

*Dry flue gas desulfurization technology* means a $SO_2$ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

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

*Emerging technology* means any $SO_2$ 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).

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

*Fluidized bed combustion technology* means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

*Fuel pretreatment* means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

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

*Gaseous fuel* means any fuel that is present as a gas at ISO conditions.

*Gross output* means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

*Heat input* means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated 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/hr) 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/hr-$ft^3$ ).

*ISO Conditions* means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

*Lignite* means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

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

*Mass-feed stoker steam generating unit* means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

*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.

*Municipal-type solid waste* means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

*Natural gas* means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Oil* means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

*Petroleum refinery* means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

*Potential sulfur dioxide emission rate* means the theoretical $SO_2$ emission (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

*Pulp and paper mills* means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

*Pulverized coal-fired steam generating unit* means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

*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 and produces steam or heats 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 for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without $SO_2$ emission control, has a $SO_2$ emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without $SO_2$ emission control, has a $SO_2$ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

*Wet flue gas desulfurization technology* means a $SO_2$control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or $SO_2$.

*Wood* means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

**§ 60.42b Standard for sulfur dioxide ($SO_2$).**

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

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

Where:

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

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

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

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

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

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential $SO_2$ emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of $SO_2$ emission, shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 50 percent of the potential $SO_2$ emission rate (50 percent reduction) and that contain $SO_2$ in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

$E_s$ = $SO_2$ emission limit, in ng/J or lb/MM Btu heat input;

$K_c$ = 260 ng/J (or 0.60 lb/MMBtu);

$K_d$ = 170 ng/J (or 0.40 lb/MMBtu);

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

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

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain $SO_2$in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the $SO_2$emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential $SO_2$emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential $SO_2$emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion $SO_2$control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the $SO_2$control system is not being operated because of malfunction or maintenance of the $SO_2$control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. 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: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine $SO_2$emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)

(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) 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, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain $SO_2$in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential $SO_2$emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential $SO_2$emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the $SO_2$emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain $SO_2$in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain $SO_2$in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential $SO_2$emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

**§ 60.43b Standard for particulate matter (PM).**

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input,

(i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or $SO_2$emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce $SO_2$emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

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

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

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

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

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, 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 PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h)

(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) 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, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce $SO_2$or PM emissions is not subject to the PM limits under §60.43b(h)(1).

**§ 60.44b Standard for nitrogen oxides ($NO_X$).**

(a) Except as provided under paragraphs (k) and (l) 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, 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 $NO_X$ (expressed as $NO_2$) in excess of the following emission limits:

| Fuel/steam generating unit type | Nitrogen oxide emission limits (expressed as $NO_2$ per heat input) | |
|---|---|---|
| | ng/J | lb/MMBTu |
| (1) Natural gas and distillate oil, except (4): | | |
| (i) Low heat release rate | 43 | 0.10 |
| (ii) High heat release rate | 86 | 0.20 |
| (2) Residual oil: | | |
| (i) Low heat release rate | 130 | 0.30 |
| (ii) High heat release rate | 170 | 0.40 |
| (3) Coal: | | |
| (i) Mass-feed stoker | 210 | 0.50 |
| (ii) Spreader stoker and fluidized bed combustion | 260 | 0.60 |
| (iii) Pulverized coal | 300 | 0.70 |
| (iv) Lignite, except (v) | 260 | 0.60 |
| (v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace | 340 | 0.80 |
| (vi) Coal-derived synthetic fuels | 210 | 0.50 |
| (4) Duct burner used in a combined cycle system: | | |

| Fuel/steam generating unit type | Nitrogen oxide emission limits (expressed as $NO_2$ per heat input) | |
|---|---|---|
| | ng/J | lb/MMBTu |
| (i) Natural gas and distillate oil | 86 | 0.20 |
| (ii) Residual oil | 170 | 0.40 |

(b) Except as provided under paragraphs (k) and (l) 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, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ in excess of a limit determined by the use of the following formula:

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

Where:

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

$EL_{go}$ = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

$H_{go}$ = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

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

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

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

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

(c) Except as provided under paragraph (l) 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, whichever date 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 $NO_X$ in excess of the emission limit for the coal or oil, or mixtures 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 affected 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.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (l) 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, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain $NO_X$ in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

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

Where:

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

$EL_{go}$ = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

$H_{go}$ = Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);

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

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

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

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

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a $NO_X$ emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as $NO_X$ emission from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific $NO_X$ emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The $NO_X$ emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific $NO_X$ emission limit will be established at the $NO_X$ emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing $NO_X$ emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific $NO_X$ limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the $NO_X$ emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on $NO_X$ emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the $NO_X$ emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the $NO_X$ emission limits of this section. The $NO_X$ emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific $NO_X$ limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the $NO_X$ standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the $NO_X$ emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ (expressed as $NO_2$) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and 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, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

$E_n$ = $NO_X$ emission limit, (lb/MMBtu);

$H_{go}$ = 30-day heat input from combustion of natural gas or distillate oil; and

$H_r$ = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

**§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.**

(a) The $SO_2$ emission standards under §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under §60.42b(d) or §60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential $SO_2$ emission rate (% $P_s$) and the $SO_2$ emission rate ($E_s$) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the $SO_2$ standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly $SO_2$ emission rate ($E_{ho}$) and the 30-day average emission rate ($E_{ao}$). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of §60.47b (a) or (b).

(ii) The percent of potential $SO_2$ emission rate (%$P_s$) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$ = Potential $SO_2$ emission rate, percent;

$\%R_g$ = $SO_2$ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = $SO_2$ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly $SO_2$ emission rate ($E_{ho}^{\circ}$) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}^{\circ}$). The Eho° is computed using the following formula:

$$E_{ho}^{\circ} = \frac{E_{ho} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{ho}^{\circ}$ = Adjusted hourly $SO_2$ emission rate, ng/J (lb/MMBtu);

$E_{ho}$ = Hourly $SO_2$ emission rate, ng/J (lb/MMBtu);

$E_w$ = $SO_2$ concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

$X_k$ = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential $SO_2$ emission rate (%$P_s$), an adjusted %$R_g$(%$R_g^o$ ) is computed from the adjusted $E_{ao}^o$ from paragraph (b)(3)(i) of this section and an adjusted average $SO_2$ inlet rate ($E_{ai}^o$ ) using the following formula:

$$\%R_g^o = 100\left(1.0 - \frac{E_{ao}^o}{E_{ai}^o}\right)$$

To compute $E_{ai}^o$ , an adjusted hourly $SO_2$ inlet rate ($E_{hi}^o$ ) is used. The $E_{hi}^o$ is computed using the following formula:

$$E_{hi}^o = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

$E_{hi}^o$ = Adjusted hourly $SO_2$ inlet rate, ng/J (lb/MMBtu); and

$E_{hi}$ = Hourly $SO_2$ inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters $E_w$or $X_k$if the owner or operator elects to assume that $X_k$= 1.0. Owners or operators of affected facilities who assume $X_k$= 1.0 shall:

(i) Determine %$P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions ($E_s$) are considered to be in compliance with $SO_2$ emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters $E_w$or $X_k$ under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure $SO_2$ emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the $SO_2$ emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for $SO_2$ for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the $SO_2$ emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for $SO_2$ for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for $SO_2$ are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid $SO_2$ emissions data in calculating $\%P_s$ and $E_{ho}$ under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid $SO_2$ emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and $E_{ho}$ pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the $SO_2$ control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate $\%P_s$ or $E_s$ under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil 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).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under §60.49b(r).

**§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.**

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

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the $NO_X$ emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM 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, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

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

(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

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

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen ($O_2$) or $CO_2$ sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The $O_2$ or $CO_2$ measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for $NO_X$ required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring $NO_X$ under §60.48(b).

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

(2) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the $NO_X$ emission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly $NO_X$ emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the $NO_X$ standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly $NO_X$ emission data for the preceding 30 steam generating unit operating days.

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

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for $NO_X$ required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of $NO_X$ shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)(E_{sg} - E_g) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of $NO_X$ from the duct burner, ng/J (lb/MMBtu) heat input;

$E_{sg}$ = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

$H_g$ = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

$H_b$ = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

$E_g$ = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the $NO_X$ concentrations. Method 3A or 3B of appendix A of this part shall be used to determine $O_2$ concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring $NO_X$ and $O_2$ and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The $NO_X$ emissions rate at the outlet from the steam generating unit shall constitute the $NO_X$ emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the $NO_X$ emission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the $NO_X$ emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance under paragraph §60.43b(h)(5) shall follow the applicable procedures under §60.49b(r).

(j) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and $O_2$ (or $CO_2$) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For $O_2$ (or $CO_2$), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

**§ 60.47b Emission monitoring for sulfur dioxide.**

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the $SO_2$ standards under §60.42b shall install, calibrate, maintain, and operate CEMS for measuring $SO_2$ concentrations and either $O_2$ or $CO_2$ concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$ and either $O_2$ or $CO_2$ concentrations shall both be monitored at the inlet and outlet of the $SO_2$ control device. If the owner or operator has installed and certified $SO_2$ and $O_2$ or $CO_2$ CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, $SO_2$ concentration data and $CO_2$ (or $O_2$) data are collected simultaneously; and

(2) In addition to meeting the applicable $SO_2$ and $CO_2$ (or $O_2$) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. $SO_2$ and $CO_2$ (or $O_2$) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the $SO_2$ data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$ emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average $SO_2$ input rate, or

(2) Measuring $SO_2$ according to Method 6B of appendix A of this part at the inlet or outlet to the $SO_2$ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$ and $CO_2$ measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily $SO_2$ emission rate, $E_D$, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A–8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19–20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average $SO_2$ emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average $SO_2$ emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly $SO_2$ emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the $SO_2$ CEMS at the inlet to the $SO_2$ control device is 125 percent of the maximum estimated hourly potential $SO_2$ emissions of the fuel combusted, and the span value of the CEMS at the outlet to the $SO_2$ control device is 50 percent of the maximum estimated hourly potential $SO_2$ emissions of the fuel combusted. Alternatively, $SO_2$ span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required $CO_2$ and $O_2$ monitors and for $SO_2$ and $NO_X$ monitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$ and $NO_X$ span values less than 100 ppm;

(ii) For all required $CO_2$ and $O_2$ monitors and for $SO_2$ and $NO_X$ monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$ and $NO_X$ span values less than or equal to 30 ppm; and

(iii) For $SO_2$, $CO_2$, and $O_2$ monitoring systems and for $NO_X$ emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for $SO_2$ (regardless of the $SO_2$ emission level during the RATA), and for $NO_X$ when the average $NO_X$ emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

**§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.**

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a $NO_X$ standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring $NO_X$ and $O_2$ (or $CO_2$) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a $NO_X$ emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

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

(d) The 1-hour average $NO_X$ emission rates measured by the continuous $NO_X$ monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for $NO_X$ is determined using one of the following procedures:

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

| Fuel | Span values for $NO_X$ (ppm) |
|---|---|
| Natural gas | 500. |
| Oil | 500. |
| Coal | 1,000. |
| Mixtures | 500 (x + y) + 1,000z |

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the $NO_X$ span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

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

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

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict $NO_X$ emission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the $NO_X$ standards of §60.44b(a)(4) or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure $NO_X$ emissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring $NO_X$ emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential $SO_2$emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce $SO_2$ or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce $SO_2$ or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, $SO_2$, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

**§ 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);

(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; and

(4) Notification that an emerging technology will be used for controlling emissions of $SO_2$. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the $SO_2$, PM, and/or $NO_X$ 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 of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the $NO_X$ standard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and $NO_X$ emission rates ( *i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion ( *i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air ( *i.e.* , flue gas $O_2$ level);

(2) Include the data and information that the owner or operator used to identify the relationship between $NO_X$ emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

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

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

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

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the $NO_X$ standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

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

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

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

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

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

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

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

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with

Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(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 excess emissions that occurred during the 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).

(2) Any affected facility that is subject to the $NO_X$ standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor $NO_X$ emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(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).

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

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for $NO_X$ under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the $SO_2$ standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average $SO_2$ emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Each 30-day average percent reduction in $SO_2$ emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which $SO_2$ or diluent ($O_2$ or $CO_2$) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

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

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

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

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

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average $SO_2$ emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent ($O_2$ or $CO_2$) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

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

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

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

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

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the $SO_2$ standards under §60.42(b) for which the minimum amount of data required under §60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment ( *i.e.* , $\%R_f$) is used to determine the overall percent reduction ( *i.e.* , $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment ( *i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any $NO_X$ emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last $NO_X$ emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) 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) or §60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific $NO_X$ standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

*Oxidation zone* is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

*Reducing zone* is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

*Total inlet air* is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* .

(i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* .

(i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The $NO_X$ emission limit shall be determined by the compliance and performance test methods and procedures for $NO_X$ in §60.46b(i).

(iii) The monitoring of the $NO_X$ emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* .

(i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific $NO_X$ standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

*Air ratio control damper* is defined as the part of the low $NO_X$ burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

*Flue gas recirculation line* is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* .

(i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* .

(i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The $NO_X$ emission limit shall be determined by the compliance and performance test methods and procedures for $NO_X$ in §60.46b.

(iii) The monitoring of the $NO_X$ emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* .

(i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* .

(1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low $NO_X$ technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring $NO_X$ emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

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

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific $NO_X$ standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* .

(i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* .

(i) The $NO_X$ emissions shall be determined by the compliance and performance test methods and procedures for $NO_X$ in §60.46b.

(ii) The monitoring of the $NO_X$ emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* .

(i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific $NO_X$ standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for $NO_X$.*

(i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the $NO_X$ emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for $NO_X$.*

(i) The $NO_X$ emissions shall be determined by the compliance and performance test methods and procedures for $NO_X$ in §60.46b.

(ii) The monitoring of the $NO_X$ emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.*

(i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

**NSPS SUBPART Dc IN 40 CFR 60 - STANDARDS OF PERFORMANCE SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS**

*If the rental package boiler for the refinery (EU-035) was constructed, modified or reconstructed after June 9, 1989, the following regulations are applicable. The unit is permitted to fire only distillate oil that will meet the fuel sulfur limitations of NSPS Subpart Dc and will demonstrate compliance by maintaining fuel supplier certifications. Requirements that are not applicable have been omitted, but the original numbering has been maintained for ease of reference.*

**§ 60.40c Applicability and delegation of authority.**

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

**§ 60.41c Definitions.**

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

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

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

*Oil* means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

**§ 60.42c Standard for sulfur dioxide ($SO_2$).**

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(i) The $SO_2$ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

**§ 60.43c Standard for particulate matter (PM).**

(e) (4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or $SO_2$emissions is not subject to the PM limit in this section.

**§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.**

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the $SO_2$ standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §60.48c(f), as applicable.

**§ 60.45c Compliance and performance test methods and procedures for particulate matter.**

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f).

**§ 60.46c Emission monitoring for sulfur dioxide.**

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the $SO_2$ standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

**§ 60.47c Emission monitoring for particulate matter.**

(c) Affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.06 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce $SO_2$ or PM emissions are not required to operate a CEMS for measuring opacity if they follow the applicable procedures under §60.48c(f).

**§ 60.48c Reporting and recordkeeping requirements.**

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of 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 §60.42c, or §60.43c.

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

(4) Notification if an emerging technology will be used for controlling $SO_2$emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(d) The owner or operator of each affected facility subject to the $SO_2$ emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the $SO_2$ emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(11)If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content of the oil.

(g) (2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the $SO_2$ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

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

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

## Operation

**TV1.** General Prohibition. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit. [Rule 62-4.030, Florida Administrative Code (F.A.C.)]

**TV2.** Validity. 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. [Rule 62-4.160(2), F.A.C.]

**TV3.** Proper Operation and Maintenance. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and 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. [Rule 62-4.160(6), F.A.C.]

**TV4.** **Not Federally Enforceable.** Health, Safety and Welfare. To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution, shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. [Rule 62-4.050(3), F.A.C.]

**TV5.** Continued Operation. An applicant making timely and complete application for permit, or for permit renewal, shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, and in accordance with applicable requirements of the Acid Rain Program, applicable requirements of the CAIR Program, and applicable requirements of the Hg Budget Trading Program, until the conclusion of proceedings associated with its permit application or until the new permit becomes effective, whichever is later, provided the applicant complies with all the provisions of subparagraphs 62-213.420(1)(b)3., F.A.C. [Rules 62-213.420(1)(b)2., F.A.C.]

**TV6.** Changes without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation:

a. Permitted sources may change among those alternative methods of operation;
b. A permitted source may implement operating changes, as defined in Rule 62-210.200, F.A.C., after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
   (1) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
   (2) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
c. Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.

[Rule 62-213.410, F.A.C.]

**TV7.** Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

## Compliance

**TV8.** Compliance with Chapter 403, F.S., and Department Rules. Except as provided at Rule 62-213.460, Permit Shield, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules. [Rule 62-4.070(7), F.A.C.]

**TV9.** Compliance with Federal, State and Local Rules. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of a facility or an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law. [Rule 62-210.300, F.A.C.]

**TV10.** Binding and Enforceable. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions. [Rule 62-4.160(1), F.A.C.]

**TV11.** Timely Information. 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 the 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. [Rule 62-4.160(15), F.A.C.]

**TV12.** Halting or Reduction of Source Activity. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity. [Rule 62-213.440(1)(d)3., F.A.C.]

**TV13.** Final Permit Action. Any Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C. [Rule 62-213.440(1)(d)4., F.A.C.]

**TV14.** Sudden and Unforeseeable Events Beyond the Control of the Source. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference. [Rule 62-213.440(1)(d)5., F.A.C.]

**TV15.** Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in this condition or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program, the CAIR Program. [Rule 62-213.460, F.A.C.]

**TV16.** Compliance with Federal Rules. A facility or emissions unit subject to any standard or requirement of 40 CFR, Part 60, 61, 63 or 65, adopted and incorporated by reference at Rule 62-204.800, F.A.C., shall comply with such standard or requirement. Nothing in this chapter shall relieve a facility or emissions unit from complying with such standard or requirement, provided, however, that where a facility or emissions unit is subject to a standard established in Rule 62-296, F.A.C., such standard shall also apply. [Rule 62-296.100(3), F.A.C.]

**Permit Procedures**

**TV17.** Permit Revision Procedures. The permittee shall revise its permit as required by Rules 62-213.400, 62-213.412, 62-213.420, 62-213.430 & 62-4.080, F.A.C.; and, in addition, the Department shall revise permits as provided in Rule 62-4.080, F.A.C. & 40 CFR 70.7(f).

**TV18.** Permit Renewal. The permittee shall renew its permit as required by Rules 62-4.090, 62.213.420(1) and 62-213.430(3), F.A.C. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) [Application for Air Permit - Long Form], 62-213.420(3) [Required Information], 62-213.420(6) [CAIR Part Form], F.A.C. Unless a Title V source submits a timely and complete application for permit renewal in accordance with the requirements this rule, the existing permit shall expire and the source's right to operate shall terminate. For purposes of a permit renewal, a timely application is one that is submitted 225 days before the expiration of a permit that expires on or after June 1, 2009. No Title V permit will be issued for a new term except through the renewal process. [Rules 62-213.420 & 62-213.430, F.A.C.]

**TV19.** Insignificant Emissions Units or Pollutant-Emitting Activities. The permittee shall identify and evaluate insignificant emissions units and activities as set forth in Rule 62-213.430(6), F.A.C.

**TV20.** Savings Clause. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect. [Rule 62-213.440(1)(d)1., F.A.C.]

**TV21.** Suspension and Revocation.

a. Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.
b. Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.
c. A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or his agent:
   (1) Submitted false or inaccurate information in his application or operational reports.
   (2) Has violated law, Department orders, rules or permit conditions.
   (3) Has failed to submit operational reports or other information required by Department rules.
   (4) Has refused lawful inspection under Section 403.091, F.S.
d. No revocation shall become effective except after notice is served by personal services, certified mail, or newspaper notice pursuant to Section 120.60(7), F.S., upon the person or persons named therein and a hearing held if requested within the time specified in the notice. The notice shall specify the provision of the law, or rule alleged to be violated, or the permit condition or Department order alleged to be violated, and the facts alleged to constitute a violation thereof.

[Rule 62-4.100, F.A.C.]

**TV22.** **Not federally enforceable.** Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules. [Rule 62-4.110, F.A.C.]

**TV23.** Emissions Unit Reclassification.

a. Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.
b. If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.

[Rule 62-210.300(6), F.A.C.]

**TV24.** Transfer of Permits. Per Rule 62-4.160(11), F.A.C., this permit is transferable only upon Department approval in accordance with Rule 62-4.120, 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. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility. The permittee shall also comply with the requirements of Rule 62-210.300(7), F.A.C., and use DEP Form No. 62-210.900(7). [Rules 62-4.160(11), 62-4.120, and 62-210.300(7), F.A.C.]

**Rights, Title, Liability, and Agreements**

**TV25.** Rights. As provided in Subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any 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 of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit. [Rule 62-4.160(3), F.A.C.]

**TV26.** Title. 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. [Rule 62-4.160(4), (F.A.C.]

**TV27.** Liability. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department. [Rule 62-4.160(5), F.A.C.]

**TV28.** Agreements.

a. 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 reasonable times, access to the premises where the permitted activity is located or conducted to:
   (1) Have access to and copy any records that must be kept under conditions of the permit;
   (2) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,
   (3) 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.
b. 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 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
c. 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.

[Rules 62-4.160(7), (9) and (10), F.A.C.]

**Recordkeeping and Emissions Computation**

**TV29.** Permit. The permittee shall keep this permit or a copy thereof at the work site of the permitted activity. [Rule 62-4.160(12), F.A.C.]

**TV30.** Recordkeeping.

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 for this permit. These materials shall be retained at least five (5) 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, and the operating conditions at the time of sampling or measurement;
   (2) The person responsible for performing the sampling or measurements;
   (3) The dates analyses were performed;
   (4) The person and company that performed the analyses;
   (5) The analytical techniques or methods used;
   (6) The results of such analyses.

[Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

**TV31.** Emissions Computation. Pursuant to Rule 62-210.370, F.A.C., the following required methodologies are to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with Rule 62-210.370, F.A.C. Rule 62-210.370, F.A.C., is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

For any of the purposes specified above, the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

a. *Basic Approach.* The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
   (1) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
   (2) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
   (3) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

b. *Continuous Emissions Monitoring System (CEMS).*
   (1) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
      (a) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or,
      (b) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.
   (2) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:
      (a) A calibrated flow meter that records data on a continuous basis, if available; or
      (b) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
   (3) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

c. *Mass Balance Calculations.*
   (1) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:
      (a) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and,
      (b) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.
   (2) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.
   (3) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

d. *Emission Factors.*
   (1) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.
      (a) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
      (b) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.
      (c) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.
   (2) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

e. *Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS.* In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

f. *Accounting for Emissions During Periods of Startup and Shutdown.* In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

g. *Fugitive Emissions.* In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

h. *Recordkeeping.* The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(1) & (2), F.A.C.]

**Responsible Official**

**TV32.** Designation and Update. The permittee shall designate and update a responsible official as required by Rule 62-213.202, F.A.C.

**Prohibitions and Restrictions**

**TV33.** Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source. [40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

**TV34.** Refrigerant Requirements. Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Chapter 62-281, F.A.C.

**TV35.** Open Burning Prohibited. Unless otherwise authorized by Rule 62-296.320(3) or Chapter 62-256, F.A.C., open burning is prohibited.

**Friday, Barbara**

| | |
|---|---|
| **To:** | nsmith@ussugar.com |
| **Cc:** | ktingberg@ussugar.com; 'dbuff@golder.com'; Satyal, Ajaya; 'Forney.Kathleen@epamail.epa.gov'; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff |
| **Subject:** | UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV |
| **Attachments:** | 0510003-032-AVSignedNoticeofFinalPermit.pdf |

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

*Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document*

Attention: Jeff Koerner

Owner/Company Name: U.S. SUGAR CORP. CLEWISTON MILL
Facility Name: U.S. SUGAR CLEWISTON MILL AND REFINERY
Project Number: 0510003-032-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: HENDRY

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0510003.032.AV.F_pdf.zip

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

## Friday, Barbara

**From:** Neil Smith [nsmith@ussugar.com]
**To:** Friday, Barbara
**Sent:** Friday, August 20, 2010 11:31 AM
**Subject:** Read: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

Your message was read on Friday, August 20, 2010 11:31:23 AM (GMT-05:00) Eastern Time (US & Canada).

## Friday, Barbara

**From:** Neil Smith [nsmith@ussugar.com]
**Sent:** Friday, August 20, 2010 11:54 AM
**To:** Friday, Barbara
**Subject:** RE: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

---

**From:** Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
**Sent:** Friday, August 20, 2010 11:30 AM
**To:** Neil Smith
**Cc:** Keith Tingberg; dbuff@golder.com; Satyal, Ajaya; Forney.Kathleen@epamail.epa.gov; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff
**Subject:** UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

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Attention: Jeff Koerner

Owner/Company Name: U.S. SUGAR CORP. CLEWISTON MILL
Facility Name: U.S. SUGAR CLEWISTON MILL AND REFINERY
Project Number: 0510003-032-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: HENDRY

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Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

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## Friday, Barbara

**From:** Keith Tingberg [ktingberg@ussugar.com]
**To:** Friday, Barbara
**Sent:** Friday, August 20, 2010 11:44 AM
**Subject:** Read: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

Your message was read on Friday, August 20, 2010 11:44:04 AM (GMT-05:00) Eastern Time (US & Canada).

## Friday, Barbara

**From:** Keith Tingberg [ktingberg@ussugar.com]
**Sent:** Monday, August 23, 2010 11:40 AM
**To:** Friday, Barbara
**Subject:** RE: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

We received the document.

Thanks.

**Keith Tingberg**
Environmental Manager
*U.S. Sugar Corporation*
ktingberg@ussugar.com
111 Ponce De Leon Avenue
Clewiston, FL 33440
Office: (863) 902-3186
Cell: (863) 233-1297
Fax: (863) 902-3149

---

**From:** Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
**Sent:** Friday, August 20, 2010 11:30 AM
**To:** Neil Smith
**Cc:** Keith Tingberg; dbuff@golder.com; Satyal, Ajaya; Forney.Kathleen@epamail.epa.gov; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff
**Subject:** UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

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Attention: Jeff Koerner

Owner/Company Name: U.S. SUGAR CORP. CLEWISTON MILL
Facility Name: U.S. SUGAR CLEWISTON MILL AND REFINERY
Project Number: 0510003-032-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: HENDRY

Click on the following link to access the permit project documents:
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Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

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## Friday, Barbara

| | |
|---|---|
| **From:** | Mail Delivery System [MAILER-DAEMON@mx1.golder.com] |
| **To:** | dbuff@golder.com |
| **Sent:** | Friday, August 20, 2010 11:30 AM |
| **Subject:** | Relayed: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV |

**Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:**

dbuff@golder.com

Subject: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

## Friday, Barbara

**From:** Buff, Dave [DBuff@GOLDER.com]
**To:** Friday, Barbara
**Sent:** Friday, August 20, 2010 11:45 AM
**Subject:** Read: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

Your message was read on Friday, August 20, 2010 11:44:39 AM (GMT-05:00) Eastern Time (US & Canada).

## Friday, Barbara

**From:** Microsoft Exchange
**To:** Satyal, Ajaya; Koerner, Jeff
**Sent:** Friday, August 20, 2010 11:30 AM
**Subject:** Delivered: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

### Your message has been delivered to the following recipients:

Satyal, Ajaya

Koerner, Jeff

Subject: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

---

Sent by Microsoft Exchange Server 2007

## Friday, Barbara

**From:** Satyal, Ajaya
**Sent:** Friday, August 20, 2010 11:30 AM
**To:** Friday, Barbara
**Subject:** Out of Office: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

I am out of the office from August 18 to August 20, 2010. I do check my e-mail frequently, I will get back to you later or have one of our Air Program staff contact you. If this is urgent, please contact Jan Wolfe with Air Program Administration at (239)332-6975, ext.115. Thank you.

## Friday, Barbara

**From:** Satyal, Ajaya
**To:** Friday, Barbara
**Sent:** Friday, August 20, 2010 1:01 PM
**Subject:** Read: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

Your message was read on Friday, August 20, 2010 1:01:16 PM (GMT-05:00) Eastern Time (US & Canada).

**Friday, Barbara**

| | |
|---|---|
| **From:** | Satyal, Ajaya |
| **Sent:** | Monday, August 23, 2010 10:59 AM |
| **To:** | Friday, Barbara |
| **Subject:** | RE: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV |

Thanks Barbara, received your mail.

AJ Satyal

---

**From:** Friday, Barbara
**Sent:** Friday, August 20, 2010 11:30 AM
**To:** nsmith@ussugar.com
**Cc:** ktingberg@ussugar.com; dbuff@golder.com; Satyal, Ajaya; Forney.Kathleen@epamail.epa.gov; abrams.heather@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Koerner, Jeff
**Subject:** UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

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Attention: Jeff Koerner

Owner/Company Name: U.S. SUGAR CORP. CLEWISTON MILL
Facility Name: U.S. SUGAR CLEWISTON MILL AND REFINERY
Project Number: 0510003-032-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: HENDRY

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Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

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## Friday, Barbara

**From:** Koerner, Jeff
**To:** Friday, Barbara
**Sent:** Friday, August 20, 2010 12:01 PM
**Subject:** Read: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

Your message was read on Friday, August 20, 2010 12:00:53 PM (GMT-05:00) Eastern Time (US & Canada).

## Friday, Barbara

**From:** Mail Delivery System [MAILER-DAEMON@mseive01.rtp.epa.gov]
**To:** Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; abrams.heather@epamail.epa.gov
**Sent:** Friday, August 20, 2010 11:30 AM
**Subject:** Relayed: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

**Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:**

Forney.Kathleen@epamail.epa.gov

Oquendo.Ana@epamail.epa.gov

abrams.heather@epamail.epa.gov

Subject: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

## Friday, Barbara

**From:** Microsoft Exchange
**To:** Gibson, Victoria
**Sent:** Friday, August 20, 2010 11:30 AM
**Subject:** Delivered: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

**Your message has been delivered to the following recipients:**

Gibson, Victoria

Subject: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

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Sent by Microsoft Exchange Server 2007

## Friday, Barbara

**From:** Gibson, Victoria
**To:** Friday, Barbara
**Sent:** Friday, August 20, 2010 11:45 AM
**Subject:** Read: UNITED STATES SUGAR CORPORATION - CLEWISTON SUGAR MILL AND REFINERY; 0510003-032-AV

Your message was read on Friday, August 20, 2010 11:45:11 AM (GMT-05:00) Eastern Time (US & Canada).