STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

SOUTHEAST RENEWABLE FUELS, LLC,

Petitioner,

vs.

OGC No. 10-3435
DEP Permit No. 0510032-001-AC
(PSD-FL-412)

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
_____/

SETTLEMENT AGREEMENT

Petitioner Southeast Renewable Fuels, LLC (SRF) and Respondent Department of Environmental Protection (Department) stipulate to the settlement of the above captioned case, and in support thereof, state:

1. On October 28, 2010, the Department issued a draft air construction permit, Permit No. 0510032-001-AC, to SRF for the construction of an ethanol producing facility using sweet sorghum as a feedstock and utilizing the leftover sweet sorghum bagasse and wood as fuel for a cogeneration power plant capable of producing up to 30 megawatts of electricity to be located in Hendry County (Draft Permit).

2. The Department received SRF's timely request for an extension of time to file a petition for formal administrative hearing on the Draft Permit on November 9, 2010 (Request for Extension) to discuss with the Department provision on the Draft Permit. The Department granted SRF's Request for Extension through December 8, 2010. During this time, the Department and SRF came to agreement on revisions to the Draft Permit.

3. SRF withdraws its Request for Extension contingent upon the Department's issuance of the Revised Draft Permit in accordance with this Settlement Agreement. Within

seven (7) days of this Settlement Agreement being signed by all parties, the Department will withdraw the Draft Permit, and will issue the Revised Draft Permit, attached hereto and incorporated herein as Attachment A.

4. Within fourteen (14) days of receipt of the Department's Revised Draft Permit, SRF will publish notice of the Revised Draft Permit, in accordance with Rule 62-210.350, Florida Administrative Code, and provide the Department proof of publication within fourteen (14) days of publication.

5. SRF waives its right to submit written comments on the Revised Draft Permit, and its right to file a request for extension of time or petition for hearing under Chapter 120, Florida Statutes, on the Revised Draft Permit, if the Department's issuance of the Revised Draft Permit becomes the final permit.

6. SRF waives its right to seek judicial review under Section 120.68, Florida Statues, by filing a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, if the Department's issuance of the Revised Draft Permit becomes the final permit.

7. The Revised Draft Permit will become the final permit to be issued to SRF, unless during the public comment period the Department receives timely written comments that result in changes to the Revised Draft Permit or a petition for hearing is filed by a person not party to this Settlement Agreement results in litigation that causes changes to the Revised Draft Permit. SRF would be a necessary party to any litigation resulting from a petition being filed by any other person regarding the issuance of the Revised Draft Permit.

8. Each party shall be responsible for its own costs and attorney's fees and waives any right that it may have against any other party for costs and attorney's fees associated with this action.

DATED this 19th day of November, 2010.

SOUTHEAST RENEWABLE FUELS, LLC

ANGELA R. MORRISON
Florida Bar No. 0855766
Hopping Green & Sams, P. A.
Post Office Box 6526
Tallahassee, FL 32314

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

for TRINA L. VIELHAUER
Chief, Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing, Settlement Stipulation, was furnished by electronic mail on this 19 day of November, 2010, to:

Angela R. Morrison
Hopping Green & Sams, P.A.
P.O. Box 6526
Tallahassee, FL 32314
amorrison@hgslaw.com

RONDA L. MOORE
Assistant General Counsel
3900 Commonwealth Blvd., MS 35
Tallahassee, FL 32399-3000
Florida Bar No. 0676411

DRAFT PERMIT

PERMITTEE

Southeast Renewable Fuels (SRF), LLC
6424 NW 5th Way
Fort Lauderdale, Florida 33309

Authorized Representative:
Mr. Don Markley, Executive Vice President

Air Permit No. 0510032-001-AC
PSD-FL-412
Expires: December 31, 2015
Facility ID No. 0510032
Sweet Sorghum-to-Ethanol Advanced Biorefinery
Hendry County

PROJECT

This is the final air construction permit authorizing the construction of an ethanol production facility using sweet sorghum as the feedstock and a cogeneration power plant that will generate up to 30 megawatts (MW) of electricity utilizing the leftover sweet sorghum stalk fiber (bagasse) from the ethanol production process as its primary fuel source. The new SRF facility, which is a Synthetic Organic Chemical Manufacturing Industry (SOCMI) plant categorized under Standard Industrial Classification (SIC) No. 2869, will be located just east of County Road (CR) 835 at the intersection of Hill Grade Road south of Clewiston, Hendry County, Florida. The UTM coordinates of the facility are Zone 17; 502.0 kilometers (km) East and 2,940.9 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations which are defined in Appendix CF of Section 4 of this permit. As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, including a determination of Best Available Control Technology (BACT).

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

Executed in Tallahassee, Florida

(DRAFT)

_____ _____
Joseph Kahn, Director (Date)
Division of Air Resource Management

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CERTIFICATE OF SERVICE

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

Don Markley, SRF: dmarkley@serenewablefuels.com
Ajaya Satyal, DEP SD: ajaya.satyal@dep.state.fl.us
Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Dee Morse, NPS: dee_morse@nps.gov
David Buff, P.E. Golder and Associates: dbuff@golder.com
Mali Chamness, Mayor, City of Clewiston: mali.chamness@clewiston-fl.gov
Janet Taylor, Chair, Hendry County Board of County Commissioners: bocc1@hendryfla.net
Mitchell Cypress, Chairman, Tribal Council, Seminole Tribe of Florida: mitchellcypress@semtribe.com
Richard Bowers, Jr., President, Seminole Tribe of Florida: richardbowers@semtribe.com
Jim Shore, Esq., General Counsel, Seminole Tribe of Florida: c/o amotlow@semtribe.com
Craig Tepper, Director, ERMD, Seminole Tribe of Florida: ctepper@semtribe.com
Vickie Gibson, DEP BAR 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.

(Draft)

_____ _____
(Clerk) (Date)

Settlement Draft

PROPOSED PROJECT

The project involves the construction of the SRF ethanol production facility that will utilize sweet sorghum as its feedstock. In addition, the project involves the construction of a cogeneration plant utilizing the leftover sweet sorghum stalk fiber (bagasse) from the ethanol production process as its primary fuel source. The cogeneration plant will generate up to 30 megawatts (MW) of electricity that will be supplied to the grid. The sweet sorghum feedstock for the SRF facility will be grown on adjacent and surrounding farmland. Juice will be extracted from the sweet sorghum and processed to increase its sucrose (sugar) concentration. The concentrated juice will then be fermented to convert the sugars to ethanol. A total of 22.11 million gallons per year (MGPY) of distilled ethanol will be produced, which will be blended with 3 percent (%) gasoline to yield a denatured ethanol product. In addition, denatured ethanol blends consisting of 10% or 85% ethanol by volume resulting in a products called E10 (10% ethanol and 90% gasoline) and E85 (85% ethanol and 15% gasoline) will be produced on-site.

The sweet sorghum bagasse will be burned in a biomass boiler with a maximum heat input rate of 536 million British thermal units per hour (mmBtu/hr) on a 4 hour average basis and 488 mmBtu/hr on a 24 hour average basis. In addition to sweet sorghum bagasse, the SRF biomass boiler will burn wood (including yard waste), biogas from on-site anaerobic bioreactors, ultralow sulfur distillate (ULSD) fuel oil with a maximum sulfur (S) concentration of 0.0015% by weight and propane. The biomass boiler will generate steam that will be utilized in the ethanol production process and in two steam turbine electrical generators (STG) to produce up to 30 MW of electrical power. Wood will be used as the primary fuel in the boiler when sweet sorghum is not available so that the boiler can continue to supply steam to the ethanol production process with sorghum syrup/molasses and/or sugar cane molasses used as the feedstocks while still generating electricity. ULSD fuel oil or propane will be used as the boiler startup, shutdown and flame stabilization fuels and in emergency equipment (two generators and one fire water pump engine).

This project will consist of the following emissions units (EU).

Facility ID No. 0510032

EU ID No.	Emissions Unit Description
001	Biomass Material Handling and Preparation
002	Cogeneration Biomass Boiler
003	Three Cooling Towers
004	Ethanol Production Process
005	Bioreactors and Biogas Flare
006	Storage Tanks
007	Truck Rack Product Loadout and Flare
008	Miscellaneous Dry Material Storage Silos
009	Two Emergency Generators
010	One Emergency Fired Pump Engine
011	Facility-Wide Fugitive VOC Equipment Leaks

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- Because SRF is a cogeneration facility, it does not operate units subject to the Title IV Acid Rain Program of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400 (PSD), F.A.C.

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- The facility is subject to Chapter 62-204.800, F.A.C for New Source Performance Standards (NSPS) under Section 111 of the CAA and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) under Section 112 of the CAA.
- The SRF facility is not subject to Clean Air Interstate rule (CAIR) but could become subject to CAIR based on final promulgation of a CAIR replacement rule by EPA.

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1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits shall be submitted to the Bureau of Air Regulation in the Division of Air Resource Management of the Department.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3881.

3. Appendices: The following Appendices are attached as a part of this permit and must be complied with by the permittee:
   a. Appendix ASME: American Society of Mechanical Engineers (ASME) Form for Abbreviated Efficiency Test;
   b. Appendix BMP: Best Management Practices;
   c. Appendix CC: Common Conditions;
   d. Appendix CEMS: Continuous Emissions Monitoring System (CEMS) Requirements;
   e. Appendix CF: Citation Formats and Glossary of Common Terms;
   f. Appendix CTR: Common Testing Requirements;
   g. Appendix Db: NSPS, Subpart Db – Standards of Performance Small Industrial-Commercial-Institutional Steam Generating Units;
   h. Appendix Eb: NSPS, 40 CFR 60, Subpart Eb – Standards of Performance for Large Municipal Waste Combustors;
   i. Appendix F: 40 CFR 75, Appendix F, Section 5 - Measurement of Boiler Heat Input Rate;
   j. Appendix GC: General Conditions;
   k. Appendix-GP: Identification of General Provisions, Subpart A from NSPS 40 CFR 60 and Subpart A from NESHAP 40 CFR 63;
   l. Appendix IIII: NSPS, Subpart IIII - Stationary Compression Ignition Internal Combustion Engines;
   m. Appendix Kb: NSPS, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels;
   n. Appendix LDAR: Preliminary Leak Detection and Repair (LDAR) Program;
   o. Appendix VVa: NSPS, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the SOCMI; and
   p. Appendix ZZZZ: NESHAP, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines (RICE).

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

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

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6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

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

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

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

9. Unconfined Emissions of Particulate Matter: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter 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; without taking reasonable precautions to prevent such emissions. Any permit issued to a facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter. Reasonable precautions include the following:

   a. Paving and maintenance of roads, parking areas and yards;

   b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing;

   c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities;

   d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne;

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e. Landscaping or planting of vegetation;

f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter;

g. Confining abrasive blasting where possible; and,

h. Enclosure or covering of conveyor systems. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

[See also Appendix BMP; Rule 62-296.320(4)(c), F.A.C.]

10. Excess Emissions: Except as required by specific conditions of this permit dealing with excess emissions with regard to individual emission units, the following conditions apply to excess emissions at SRF.

    a. Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

    b. Malfunction: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

    c. Department Discretion: Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.

    d. Department Notification: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.

    [Rule 62-210.700, F.A.C.]

11. NSPS, Subpart VVa: Emission units associated with the SRF project that can leak volatile organic compounds (VOC) are subject to NSPS Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the SOCMI. A requirement of Subpart VVa is the development of a leak detection and repair (LDAR) program. A preliminary LDAR program plan is included as Appendix LDAR in Section IV of this permit. The permittee is required to submit a final LDAR program plan to the Compliance Authority for approval no later than 90 days before the SRF facility becomes operational. The SRF must demonstrate compliance with NSPS, Subpart VVA no later than 180 days after the initial startup of the SRF facility. [NSPS, Subpart VVa and Rule 62-4.070(3), F.A.C. Reasonable Assurance]

12. Equipment Subject to NSPS, Subpart VVa: Equipment such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves, line valves and flanges or other connectors in VOC service and any devices or systems subject to NSPS, Subpart VVa and the associated emissions unit must be identified with a listed submitted to the Compliance Authority no later than 90 days before the SRF facility becomes operational. [Rule 62-4.070, F.A.C. Reasonable Assurance]

13. Objectionable Odors Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. The permittee shall submit an odor control plan (OCP) to the Compliance Authority no later than 90 days before the SRF facility becomes operational that addresses the procedures and practices that will be used to control facility wide odors. [Rule 62-296.320(2), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

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{Permitting Note: An objectionable odor is defined in Rule 62-210.200(Definitions), F.A.C., as 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.}

14. Open Burning Prohibited: No person shall ignite, cause to be ignited, or permit to be ignited, any material which will result in any prohibited open burning as regulated by chapter 62-256, F.A.C.; nor shall any person suffer, allow, conduct or maintain any prohibited open burning.
[Rule 62-256.300, F.A.C.]

15. General Visible Emissions (VE) Standard:

    a. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity).

    b. Notwithstanding subparagraph 62-296.320(4)(b)1., F.A.C., above, the owner or operator of an emissions unit subject to the general visible emission standard may request the Department to establish a higher visible emissions standard for that emissions unit. The owner or operator may request that a visible emissions standard be established at that level at which the emissions unit will be able, as indicated by compliance tests, to meet the opacity standard at all times during which the emissions unit is meeting the applicable particulate matter standard. The Department shall establish such a standard, through the permitting process, if it finds that:

        (i) The emissions unit was in compliance with the applicable particulate emission standard while a compliance test was being conducted but failed to comply with the general visible emissions standard during the test;

        (ii) The emissions unit and associated air pollution control equipment were operated and maintained in a manner to minimize the opacity emissions during the compliance test; and

        (iii) The emissions unit and associated air pollution control equipment were incapable of being adjusted or operated in such a manner as to meet the opacity standard.

        (iv) 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.

    [Rule 62-296.320(4)(b) F.A.C, General Visible Emissions Standard]

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A. Biomass Material Handling and Preparation (EU-001)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
001	Biomass delivery, handling and preparation: • Ethanol Process Feedstock: Freshly harvested sweet sorghum from adjacent/surrounding area farmland is delivered by trucks to the SRF facility. The trucks will be weighed on a weighing bridge as they enter the unloading area. The sorghum in the trucks is then transferred to the feed table via a tipping trailer/railcar unloader or front end unloader. The feed table is equipped with chains that convey the sorghum towards the main conveyor that feeds the juice extraction system. Sorghum bagasse is produced during the juice extraction process. • Boiler Fuel Biomass: Sweet sorghum bagasse from the juice extraction process will be used as the primary fuel in the SRF biomass boiler. The bagasse will be sent directly to the boiler or stored in a storage pile in the biomass yard. Prepared (sized and partially dried) tree wood chips, including yard waste which constitutes municipal solid waste (MSW), will also be used as boiler fuel. The wood will be delivered to the plant site by truck utilizing the weighing and unloading system discussed above. The wood and yard waste will be stored in storage piles in the biomass yard. • Biomass Fuel Feed System: A single biomass fuel feed system for the boiler will be used. The system will consist of a drying system for the sweet sorghum bagasse, covered conveyors, boiler metering bins and biomass storage piles (bagasse and wood chips). The biomass fuel will be fed from the storage piles to the conveyor system using front-end loaders. Only one feed system is required, since sorghum bagasse and wood may be fired independently or in combination in the boiler. • Biomass Design Throughput: The maximum amount of biomass burned in the boiler is estimated at 382,080 tons per year (TPY) of sorghum bagasse and 140,069 TPY of wood/yard waste, for a total of 522,149 TPY. For the biomass handling system, an additional 10 percent (%) overhead is assumed for year-to-year variability in biomass fuel handled, resulting in 420,288 TPY of sorghum bagasse and 154,076 TPY of wood throughput.

EQUIPMENT

1. Biomass Delivery, Handling and Preparation: The permittee is authorized to install the following major pieces of equipment for the delivery, handling and processing of the sweet sorghum used in the ethanol production process and the bagasse and wood/trash used as boiler fuel:
   - Weighing bridge truck scale(s);
   - Tipping trailer/railcar unloader(s);
   - Sweet sorghum bagasse press drying system;
   - Feed table with transfer chains;
   - Enclosed transfer conveyors consisting of reclaim, return, transfer, distribution and surplus conveyors; and
   - Biomass yard waste containing biomass fuel storage piles (bagasse and wood).

   [Application No. 0510032-001-AC and Rule 62-4.070(3), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive particulate matter (PM), PM with a mean diameter of 10 micrometers (µm) or less (PM_{10}) and PM with a mean diameter of 2.5 µm or less ($PM_{2.5}$); henceforth called PM, biomass conveyors shall be enclosed. Where required to meet the opacity requirement given in

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Specific Condition 10 of this subsection, the permittee shall install dust collectors on the conveyor transfer and drop points. The dust collectors shall be designed to obtain an outlet PM loading of 0.005 grains per dry standard cubic foot (gr/dscf).

{Permitting Note: Enclosed conveyors means that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs.}

[Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

3. Fugitive Dust Control: SRF shall utilize reasonable precautions for controlling fugitive PM emissions from this emission unit. These include but are not limited to:
   - Enclosing material drop points, transfer points, shredders and screens wherever practical;
   - Contouring storage piles to minimize wind erosion;
   - Utilizing water sprays on storage piles as needed;
   - Paving all main plant roads;
   - Watering of gravel surfaces as needed to control dust; and
   - Weekly sweeping and watering of paved surfaces as needed to remove dust.

   The permittee shall also comply with additional precautions listed in Appendix BMP- Best Management Practices and **Specific Condition 9** of Section 2 of this permit.

   [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Roadways: The plant roadways shall be paved and during dry conditions wetted sufficiently to maintain surface moisture to minimize fugitive dust emissions. Roadways shall be swept weekly with a vacuum sweeper in good working order to prevent the buildup of dirt and silt on the roadway surfaces. A record of the sweeping shall be kept and made available to the Compliance Authority upon request.
   [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

5. Gravel Areas: The gravel surfaces at the SRF facility shall be wetted sufficiently during dry conditions to maintain surface moisture to minimize fugitive dust emissions. A record of the wetting shall be kept and made available to the Compliance Authority upon request.
   [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

6. Sweet Sorghum Bagasse and Wood Biomass Storage Piles: The biomass storage piles will be located in the biomass yard in the southeastern quadrant of the SRF site. To control odors and minimize the chance of spontaneous combustion, biomass in the storage piles shall be used in a first-in first-out (FIFO) basis. Piles will be wetted as necessary to minimize fugitive dust emissions. Contouring storage piles shall be done to minimize wind erosion. Overall, biomass storage pile management shall follow the procedures described in Appendix BMP of this permit.
   [Application No. 0510032-001-AC; Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

7. Authorized Ethanol Production Biomass: Biomass used in the ethanol production process at the SRF facility shall be sweet sorghum feedstock. In addition, sweet sorghum syrup/molasses and/or sugarcane molasses may be used as the feedstock when sweet sorghum feedstock is not available.
   [Application No. 0510032-001-AC and Rule 62-4.070(3), F.A.C.]

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8. Authorized Boiler Fuel Biomass: Biomass authorized to be used as fuel in the biomass boiler at the SRF consists of sweet sorghum bagasse, wood chips and yard waste as per 40 CFR §60.51b. Appendix BMP further defines the types of biomass that shall and shall not be used at the SRF facility in the ethanol production process and as boiler fuel and includes quality assurance (Q&A) procedures to ensure the biomass used meets the requirements specified in this permit.
[Application No. 0510032-001-AC and Rule 62-4.070(3), F.A.C.]

9. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year).
[Application No. 0510032-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

10. Opacity Standard: As determined by EPA Method 9, there shall be no visible emissions (VE) greater than 5% opacity at drop points, transfer points and dust collector outlets (if installed).
[Rule 62-212.400(5)(c), F.A.C.]

11. Best Management Practices (BMP): A control plan to control PM emissions from biomass (sweet sorghum, sweet sorghum bagasse and wood/yard waste) delivery, handling and preparation is given in Appendix BMP and shall be followed at all times by the permittee. This plan also addresses measures to minimize the chance of the spontaneous combustion of biomass storage piles and Q&A measures for biomass delivered to the SRF facility. As the engineering details of the Biomass Delivery, Handling and Preparation emissions unit becomes finalized, the permittee shall submit an updated BMP plan to the Compliance Authority no later than 90 days before the SRF facility becomes operational.
[Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

{Permitting Note: PM emissions from biomass deliveries, bagasse handling and wood/trash handling during operation of the SRF facility are estimated to be 21 tons in any consecutive twelve month period.}
[Application No. 0510032-001-AC]

NSPS SUBPART Eb APPLICABILITY

12. Cofired Combustor: The SRF facility may use yard trash as a component of its fuel mix for the facility's biomass boiler. As per 40 CFR §60.51b yard waste is defined as municipal solid waste (MSW). To be exempt from the requirements of NSPS 40 CFR 60, Subpart Eb for large municipal solid waste combustors, the biomass boiler must meet the definition of a cofired combustor per 40 CFR §60.51b and meet the requirements of §60.50b(j)(1) to §60.50b(j)(3). The permittee must keep records on site showing that the biomass boiler is a cofired combustor and that the unit is combusting a fuel feed stream, 30% or less of the weight of which is comprised, in aggregate, of MSW (yard waste) as measured on a calendar quarter basis. These records must be made available to the Compliance Authority upon request. To meet the definition of a cofired combustor, the fuel slate for the boiler can consists of no more than 30% by weight of yard waste on a quarterly basis. The applicable portions of Subpart Eb are contained in Appendix Eb of this permit.
[40 CFR 60, Subpart Eb and Rule 62-4.070(3), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

13. Initial Compliance Tests: The drop points, transfer points and dust collector outlets (if installed) of this emissions unit shall be tested to demonstrate initial compliance with the emissions standards for opacity given in **Specific Condition 10** of this subsection. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit.
[Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

14. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the drop points, transfer points and dust collector (if installed) outlets of the emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity given in **Specific Condition 10** of this subsection.
[Rules 62-4.070(3) and 62-297.310(7)(a)4, F.A.C.]

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15. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

16. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources.

The above method is described in Appendix A of 40 CFR 60 included as Appendix GP of this permit and are 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 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

RECORDS AND REPORTS

17. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

18. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of biomass consisting of sweet sorghum, sweet sorghum syrup/molasses, sugarcane molasses, wood and yard trash delivered, handled and processed on a daily, monthly, quarterly and 12 month rolling average basis. These records shall be submitted to the Compliance Authority on a quarterly basis or upon request. [Rule 62-4.070(3), F.A.C.]

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B. Cogeneration Biomass Boiler (EU-002)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
002	*Description*: The boiler will be a biomass-fueled bubbling fluidized bed (BFB) or stoker (grate) type boiler wherein biomass (sweet sorghum bagasse, wood chips and yard waste as per 40 CFR §60.51b), biogas, ULSD fuel oil and propane are combusted to generate high temperature and high pressure steam. The steam will then be used in the ethanol production process and also sent to two STG to generate up to 30 MW of electrical power. *Fuels*: Sweet sorghum bagasse, a residual from the ethanol production process, will be used as the primary fuel in the biomass boiler with wood chips including yard waste (MSW) and biogas produced in onsite anaerobic reactors used as supplemental and backup fuels. In addition, the boiler will be capable of combusting ULSD fuel oil and propane for startup, shutdown and flame stabilization. *Capacity*: The maximum heat input capacity to the boiler is 536 mmBtu/hr on a 4 hour basis and 488 mmBtu/hr on a 24-hour basis. Steam production capability will be approximately 283,800 pounds per hour (lb/hr). The maximum heat input capacity using fossil fuels in the biomass boiler shall be physically constrained by burner design to be less than 250 mmBtu/hr so the boiler is not subject to 40 CFR 60 NSPS, Subpart Da. *Controls*: Good combustion practices (GCP) leading to the efficient combustion of biomass in the boiler, including an over-fired air (OFA) system, to minimize formation of PM, nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC) and HAP; Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR) or a combination of the two with urea or anhydrous ammonia (NH_3) injection to destroy NO_X; an oxidation catalyst (ox-cat) system (if needed) to control VOC, CO and HAP ; use of inherently clean fossil fuels fired in low-NO_X burners (LNB) for boiler startup, shutdown and flame (bed) stabilization to minimize formation of PM, NO_X, sulfur dioxide (SO_2) and HAP; an dry sorbent injection system (DSIS) utilizing lime, trona, or sodium bicarbonate to control SO_2, sulfuric acid mist (SAM) and acid gas HAP; a wet scrubber to remove hydrogen sulfide (H_2S) from the biogas prior to combustion in the boiler to minimize SO_2 emissions; a wet sand separator (cyclone) and a electrostatic precipitator (ESP) or fabric filter baghouse to further control PM and VE, i.e., opacity; and, if necessary, a hydrogen chloride (HCl) and hydrogen fluoride (HF) control strategy to ensure SRF is minor source for HAP emissions. *Stack Parameters*: Flue gas from the biomass boiler will discharge to the atmosphere via a stack with a design height of 150 feet and a design diameter of 10 feet. The flue gas exit temperature will be approximately 361 degrees Fahrenheit (°F) with a design volumetric flow rate of 180,505 actual cubic feet per minute (acfm). *Continuous Emissions and Opacity Monitoring Systems (CEMS, COMS)*: Emissions of CO, NO_X, SO_2 and HCl will be monitored and recorded by CEMS. VE (opacity) will be monitored and recorded by COMS. *Applicability of 40 CFR Subpart Db (NSPS Subpart Db)*: This unit is subject to NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units because it has a maximum heat input capacity greater than 100 mmBtu/hr from combusted fuels and is not subject to NSPS Subpart Da because it has a maximum heat input capacity less than 250 mmBtu/hr from combusted fossil fuels. [Application No. 0510032-001-AC]

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B. Cogeneration Biomass Boiler (EU-002)

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for the biomass-fueled boiler that represent the Best Available Control Technology (BACT) for emissions of NO_X, PM/PM_{10}, VOC, SO_2 and CO. The biomass-fueled boiler is subject to the federal New Source Performance Standards (NSPS) in Subpart Db (industrial boilers) of 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C. NSPS Subpart Db for Industrial Boilers is provided in Appendix Db of this permit.}

EQUIPMENT

1. Construction of Biomass-Fueled Boiler: The permittee is authorized to construct one biomass-fueled BFB or stoker boiler with a maximum heat input rate of 536 mmBtu/hr on a 4 hour average basis and 488 mmBtu/hr on a 24 hour basis for steam generation at the SRF facility. The boiler shall have a multi-stage superheater, air heater, and economizer. LNBs shall be utilized for the ULSD fuel oil and propane firing. The boiler shall include:
   - Biomass fuel feeders;
   - High-performance OFA system consisting of air headers, air nozzles, dampers and an OFA fan;
   - Soot blowers;
   - Forced draft fan;
   - Induced draft (ID) fan; and
   - Pneumatic distribution air fans.

   [Application No. 0510032-001-AC]

2. Air Pollution Control Equipment: To comply with the emission standards of this permit, the permittee shall install the following air pollution control equipment on the biomass boiler.

   a. *Wet Sand Separator (Cyclone)*: The permittee shall design, install, operate and maintain a wet sand separator to remove fine sand particles from the flue gas exhaust prior to the ESP and help in the control of acid gas HAP emission. The wet sand separator shall be on line and functioning properly whenever the boiler is in operation. If necessary, the wet sand separator shall be modified to aid in the removal of acid gases to meet the emission limits S**pecified Condition 10** of this subsection.

   b. *ESP or Baghouse*: The permittee shall design, install, operate and maintain an ESP or fabric filter baghouse to remove PM from the flue gas exhaust and achieve the PM standards specified in this subsection. During startup conditions, the ESP shall be on line and functioning properly prior to combusting any biomass. During normal operation, the ESP shall be on-line and functioning properly at all times.

   c. *SNCR, SCR or a Combined SNCR/SCR System*: The permittee shall design, install, operate, and maintain a urea or anhydrous ammonia (NH_3) based SNCR, SCR or a combined SNCR/SCR system to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standards specified in this subsection. The SNCR, SCR or a combined SNCR/SCR system shall be on line and functioning properly whenever the boiler is in operation, other than during startup conditions. During startup conditions, the SNCR, SCR or combined SNCR/SCR manufacturer's instructions shall be followed regarding operation of the systems.

   d. *DSIS*: The permittee shall design, install, operate, and maintain a DSIS to inject lime, trona, or sodium bicarbonate into the flue gas to control SO_2 emissions to the limits specified in this subsection. The DSIS will also help control acid gas HAP emissions. The HCl and SO_2 CEMS output data expressed in lbs/hr averaged over a 24 hour period shall be reviewed by trained plant personnel on a daily and monthly basis to determine required operation of, or adjustment to the sorbent injection augmentation to ensure the HCl, HF and SO_2 emission standards will be maintained. CEMS based HCl and SO_2 emissions data shall be reported to the Department on a quarterly basis.

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{Permitting note: Sorbent injection augmentation is not continuously required if compliance with the HCl, HF and SO_2 emission standards is established by the CEMS output data.}

e. *Ox-Cat or SCR System*: If necessary, the permittee shall design and build the project to facilitate future installation of a SCR or an ox-cat system to control in conjunction with GCP emissions of NO_X, CO, VOC and organic HAP emissions to the standards specified in this subsection. The permittee may install an SCR or an Ox-Cat system during project construction or after notifying the department at a future data. After notification, the permittee shall have twelve consecutive months to complete the SCR or Ox-Cat system installation. The permittee may install the SCR or Ox-Cat system at without an additional permit application any time prior to expiration of this construction permit.

f. *Biogas Scrubber*: The permittee shall design, install, operate and maintain a wet scrubber to remove H_2S from the biogas from the bioreactors prior to combustion in the biomass boiler. The scrubber shall have a design control efficiency of at least 98% and shall be on line and operating as necessary to meet the SO_2 emissions limits specified in this subsection.

g. *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.]

{Permitting Note: In addition to the Ox-Cat system, GCP will be used to control emissions of CO and VOC to the limits specified in this permit.}

[Applicant's Request; Application No. 0510032-001-AC; Rules 62-212.400(10) (PSD), Control Technology Review; 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Authorized Fuels: The biomass boiler is authorized to combust as its primary fuels: sweet sorghum bagasse that is a byproduct from the ethanol production process; the biogas produced in onsite anaerobic reactors; wood chips; and yard waste as defined in 40 CFR §60.51b. In addition, the boilers are authorized to combust ULSD fuel oil or propane for startup, shutdown and flame stabilization. SRF has estimated the fuel mix to be used in the biomass boiler on an annual basis. This estimate fuel mix in mmBtu/yr is provided below. [Application No. 0510032-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Operational Scenario	Annual Average[1] Heat Input from Fuels in mmBtu/yr					Total mmBtu/yr[2]
	Bagasse	Wood	ULSD Fuel Oil	Biogas	Propane	
Normal	2,903,808	1,190,583	0	0	0	4,094,391
Max. Biogas	2,903,808	907,352	0	231,420	0	4,042,580
Max. ULSD	2,903,808	639,543	450,240	0	0	3,993,591
Max. Propane	2,903,808	639,543	0	0	450,240	3,993,591

1. Annual average based on an average of 258,000 lb/hr of steam production, 488 mmBtu/hr of heat input or 8,400 hours per year of boiler operation.
2. Based on heating values as follows: bagasse – 3,800 Btu/hr (wet); wood – 4,250 Btu/hr (wet); ULSD fuel oil – 138,000 Btu per gallon; biogas – 725 Btu per standard cubic feet; and propane – 90,500 Btu per gallon.

4. Boiler Heat Input Rate: The maximum heat input rate from all fuel combinations in the biomass boiler is 536 mmBtu/hr on a 4 hour average basis and 488 mmBtu/hr on a 24 hour average basis. Emission rates are based on the heat input of 488 mmBtu/hr. The permittee shall use the thermal efficiency method to calculate the boiler heat input rate, using the steam rate, steam pressure, and steam temperature measurements required per **Specific Condition 18** of this subsection, and feedwater temperature and pressure, to determine net enthalpy. The design boiler efficiency shall be used provided the boiler efficiency test required in **Specific Condition 17** of this subsection is at least 90% of the design boiler efficiency. The procedure given in Appendix ASME of this permit shall be used to measure the boiler efficiency. As an

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alternative, the procedures given in Appendix F of this permit may be used to calculate boiler heat input. [Application No. 0510032-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Heat Input from Fossil Fuels: The maximum heat input capacity from combusting ULSD fuel and/or propane in the biomass boiler, as determined by the physical design of the boiler and design characteristics of the boiler burners must be limited to less than 250 mmBtu/hr.
[Application No. 0510032-001-AC; NSPS Subpart Db; Rules 62-4.070(3); and 62-210.200(PTE), F.A.C.]

6. Hours of Operation: The hours of operation for the biomass boiler are restricted to 8,400 hours in any consecutive 12 month period.
[Application No. 0510032-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

7. GCP: The emission standards established by this permit rely on "good combustion practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the steam generating unit and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good combustion practices as well as methods of minimizing excess emissions. [Rule 62-4.070(3), F.A.C. and 62-212.400(5), F.A.C.]

NSPS APPLICABILITY

8. Subpart Eb - Cofired Combustor: The SRF facility will use yard waste as a component of its fuel mix for the facility's biomass boiler. As per 40 CFR §60.51b yard waste is defined as MSW. To be exempt from the requirements of NSPS 40 CFR 60, Subpart Eb for large municipal solid waste combustors, the boiler must meet the definition of a cofired combustor per 40 CFR §60.51b and meet the requirements of §60.50b(j)(1) to §60.50b(j)(3). The permittee must keep records on site showing that the biomass boiler is a cofired combustor and that the unit is combusting a fuel feed stream, less than 30% of the weight of which is comprised, in aggregate, of MSW as measured on a calendar quarter basis. These records must be made available to the Compliance Authority upon request. The applicable portions of Subpart Eb are contained in Appendix Eb of this permit. [40 CFR 60, Subpart Eb and Rule 62-4.070(3), F.A.C. Reasonable Assurance]

9. Subpart Db - Steam Generating Units: The SRF biomass boiler must meet all applicable requirements of NSPS 40 CFR 60, Subpart Db - Industrial-Commercial-Institutional Steam Generating Units. Subpart Db is contained in Appendix Db of this permit. [Application No. 0510032-001-AC and 40 CFR 60, Subpart Db]

EMISSIONS STANDARDS

10. Emission Limits: Emissions from the biomass boiler at SRF facility shall not exceed the following standards.

Parameter	Limit	Basis	Compliance
NO_X [a]	0.10/0.08 lb/mmBtu	BACT	30-day rolling by CEMS
SO_2 [b]	0.060 lb/mmBtu	BACT	30-day rolling by CEMS
CO	0.10 lb/mmBtu	BACT	30-day rolling by CEMS [l]
	240 TPY	Rule 62-4.070(3), F.A.C.	12-month rolling by CEMS [l]
SAM [c]	0.003 lb/mmBtu	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Test
HCl [d]	2.0 TPY	Emission Cap Rule 62-4.070(3),F.A.C.	12-month, rolled monthly by CEMS
HF [d]	0.475 lb/hr	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Tests
Σ HCl, HF, Cl_2, Organic HAP, Metal HAP [e]	20.0 TPY	Rule 62-4.070(3), F.A.C.	12-month Blocks CEMS + Initial and Annual Stack Tests [f]
PM/PM_{10} (filterable) [g]	0.015 lb/mmBtu	BACT	Initial and Annual Stack Tests

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B. Cogeneration Biomass Boiler (EU-002)

Parameter	Limit	Basis	Compliance
VE [h]	10% Opacity (20% once/hr)	BACT	6-minute blocks by COMS Initial Stack Test
VOC	0.010 lb/mmBtu	BACT	Initial and Annual Stack Tests
NH_3 Slip [i]	35/25 ppmvd @ 7% O_2	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Tests
Heat Input Rate [j]	488 mmBtu/hr	Rule 62-210.200(PTE), F.A.C.	24-hour, by 40 CFR 75, App. F [k]
	536 mmBtu/hr	Rule 62-4.070(3), F.A.C.	4-hour, by 40 CFR 75, App. F [k]

a. CEMS based NO_X limit in pounds per million Btu heat input (lb/mmBtu) will ensure compliance with NSPS Subpart Db NO_X limit of 0.20 lb NO_X/mmBtu. Limit of 0.10 lb/mmBtu is for the stoker boiler option while the 0.08 lb/mmBtu limit is for the BFB boiler option.
b. CEMS based SO_2 limit in lb/mmBtu will ensure compliance with NSPS Subpart Db SO_2 limit of 0.20 lb SO_2/mmBtu.
c. SAM emission limit exceeds 7 TPY triggering PSD for this pollutant requiring a BACT.
d. Individual HCl and HF mass emission limits to provide reasonable assurance that annual emissions of all HAP from the SRF facility will be less than 25 TPY. RATA testing for CEMS may be used in lieu of initial stack testing.
e. Sum (Σ) of the following hazardous air pollutants (HAP): HCl, HF, organic HAP [C_2H_4O (acetaldenhyde), C_3H_4O (acrolein), C_6H_6 (benzene), $C_{24}H_{38}O_4$ (Bis(2-ethylhexyl)phthalate), Cl_2 (chlorine), $C_6H_4Cl_2$ (1,4-Dichlorobenzene), CH_2O (formaldehyde), C_6H_{14} (Hexane), C_8H_8 (styrene), C_7H_8 (toluene), PAH/POM (polycyclic aromatic hydrocarbon/polycyclic organic matter)] and metal HAP [Cr (chromium), Pb (lead), Mn (manganese), Ni (nickel)].
f. During each fiscal year (October 1 to September 30), the emission limit is 12 month block of HCl CEMS emissions data in TPY combined with HF, organic and metal HAP emission rates in TPY from a stack test during the same fiscal year.
g. Filterable fraction as measured by EPA Method 5. By meeting this emission limit, the 0.2 lb/mmBtu limit of Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment will also be met.
h. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%. By meeting the VE standard the 30% opacity except that 40% opacity for no more than 2 minutes in any hour of Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment will also be met.
i. Anhydrous ammonia (NH_3) slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O_2). The 35 ppmvd applies to the stoker boiler option while the 25 ppmvd applies to the BFB boiler option.
j. Except for initial and annual HF stack test emission rates, 24 hour average heat input rate of 488 mmBtu/hr in conjunction with lb/mmBtu limits obviates the need for lb/hr emission limits. The 4 hour average of 536 mmBtu/hr input is included as a limit to ensure the validity of air modeling results.
k. With the approval of the Compliance Authority, the Permittee may use the method given in Appendix ASME to calculate the boiler heat input rate.
l. The 30-day limit is subject to CEMS data exclusion. The 12-month limit is not subject to CEMS data exclusion.

[Application No. 0510032-001-AC; Rule 62-212.400(10) (PSD), Control Technology Review; and 40 CFR 60, Subpart Db]

11. Continuous Monitoring Requirements: The permittee shall install, calibrate, maintain and operate CEMS, a COMS and a diluent monitor to measure and record the emissions of SO_2, NO_X, CO and HCl, and opacity from the biomass boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based and COMS-based emission standards in **Conditions 10** above. Each CEMS and COMS shall be installed, calibrated and properly functioning within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup and prior to the initial performance tests. Within one working day of discovering emissions in excess of a SO_2, NO_X, HCl or CO emission limit (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *SO_2 CEMS*: The SO_2 CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75.

    b. *NO_X CEMS*: The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Recordkeeping and reporting shall be conducted pursuant to Subpart Db in 40 CFR 60 and Subparts F and G in 40 CFR 75.

    c. *CO CEMS*: The CO CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60,

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Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

d. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method Other Test Method (OTM 22) or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, EPA Method OTM 23 or alternative procedures approved by the Department. A Data Assessment Report shall be made each calendar quarter and reported semiannually to the Compliance Authority. The RATA tests required for the HCl monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HCl monitor span values shall be set, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided to the Department prior to installation and operation of the CEM system.

e. *COMS*: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

f. *Diluent Monitor*: The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rule 62-212.400(10), F.A.C.; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C.; and 40 CFR 60, Subpart Db and Appendices]

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

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

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

14. Emission Limit Compliance and Excess Emissions: Because of the long-term nature of the NO_X, SO_2 and HCl mass emission rate limits and as part of PSD and the associated BACT determination, all emissions data for these pollutants, including periods of startup, shutdown and malfunction, shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), 62-210.200(PTE); Rule 62-212.400(10) (PSD), Control Technology Review; and Rule 62-4.070(3), F.A.C.]

15. Excess Emissions Allowed for CO: As specified in this condition, excess emissions resulting from startup, shutdown and documented malfunctions are allowed provided that operators employ the best operational

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practices to minimize the amount and duration of emissions during such incidents. CO emission data exclusions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. *Cold Startup*: For a cold startup of the boiler, CO emission data exclusions shall not exceed six (6) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the boiler following a shutdown lasting at least 24 hours.

b. *Warm Startup*: For a warm startup of the boiler, CO emission data exclusions shall not exceed three (3) hours in any 24-hour period. A warm "startup of the steam turbine system" is defined as startup of the boiler following a shutdown lasting less than least 24 hours.

c. *Shutdown*: For shutdown of the boiler CO emission data exclusions shall not exceed two (2) hours in any 24-hour period. Shutdown is defined as the cessation of the operation of the boiler for any purpose after steam generation drops below 100,000 lb/hr.

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

    a. Opacity: During startup, shutdown and malfunctions, the stack opacity shall not exceed 20% based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity. [Rule 62-210.700(5), 62-210.200(PTE); Rule 62-212.400(10) (PSD), Control Technology Review; and Rule 62-4.070(3), F.A.C.]

TESTING REQUIREMENTS

17. Boiler Performance Test: Within 180 days of first fire on the primary fuel (sweet sorghum bagasse) and biogas as a supplemental fuel, with ULSD fuel oil or propane used for flame stabilization; the SRF shall conduct a test to determine the boiler thermal efficiency. Within 180 days of first fire with wood/sorghum trash as the primary fuels and biogas as a supplemental fuel, with ULSD fuel oil or propane for flame stabilization; the SRF shall conduct a test to determine the boiler thermal efficiency. Each test shall be conducted in general abbreviated accord with ASME PTC 4, 1998 (See Appendix ASME of this permit). The abbreviated test procedure shall be agreed upon by all parties. The test shall be conducted when firing only the specified fuels with as close of fuel mix and heating values to the boiler design fuel mix and heating values as practical and shall be at least three hours long. The boiler steam conditions and production rate shall be monitored and recorded during the test. The primary fuel firing rate (in tons per hour and cubic feet per minute as appropriate) shall be calculated and recorded based on the steam parameters. Samples of the as-fired sweet sorghum bagasse and wood/sorghum trash shall be analyzed for the heating value (Btu/lb) and moisture content (%). A sample of the as-fired biogas shall be analyzed for the heating value (Btu/ft^3). The actual heat input rate (mmBtu/hour) shall be determined using the method given in **Specific Condition 16** below. Results of the test shall be submitted to the Compliance Authority within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted. [Applicant's Request and Rule 62-4.070(3), F.A.C.]

18. Boiler Heat Input Rate Calculation: The permittee shall use the thermal efficiency method in Specific Condition 4 of this subsection to calculate the boiler heat input rate. The procedure given in Appendix ASME of this permit shall be used to measure the boiler efficiency. As an alternative, the procedures given in Appendix F of this permit may be used to calculate boiler heat input. If used, Section 5 of Appendix F of 40 CFR 75 provides a methodology for calculation of the heat input rate to a boiler using F-Factors. The applicable portions of 40 CFR 75 for the calculation of the heat input rate to the biomass boiler at the SRF facility is contained in Appendix F of this permit. This procedure may be used to calculate the heat input

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rate in mmBtu/hr to the biomass boiler. [Rule 62-4.070(3), F.A.C. Reasonable Assurance]

19. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, the biomass boiler shall be tested to demonstrate initial compliance with the emission standards for CO, NO_X, PM, SO_2, VOC, SAM, HF, HCl, opacity, anhydrous ammonia slip (NH_3), metal HAP and organic HAP. Relative Accuracy Test Audit (RATA) test for CEM can constitute initial stack tests for these pollutants. The tests shall be conducted within the maximum heat input rate to each boiler, but not later than 180 days after the initial startup of the boiler. Subsequent compliance stack tests for ammonia slip, SAM, PM, VOC, HF, metal HAP and organic HAP shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90% and 100% of the maximum heat input rate when firing only the primary fuels. CEMS data for CO, NO_X, SO_2 and HCl along with COMS data for opacity shall be reported for each run of the required stack tests for ammonia slip, SAM, PM, VOC, HF, metal HAP and organic HAP. 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(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; and 40 CFR 60.8]

    {Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed. The initial HCl test is for informational purposes only to provide an early indication of likely compliance with the annual limit of 2.0 TPY.}

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

EPA Method	Description of Method and Comments
CTM-027 320	Measurement of Ammonia Slip *or* Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
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 Matter Emissions from Stationary Sources
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
8	Determination of Sulfuric Acid and Sulfur Dioxide Emissions from Stationary Sources
9	Visual Determination of the Opacity
10B	Measurement of CO Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the total hydrocarbons (THC) emissions measured by Method 25A.}*
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)
29	Metals Emissions from Stationary Sources

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 Compliance Authority. [Rules 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

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OTHER MONITORING REQUIREMENTS

21. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices on the biomass boiler 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.
[Applicant's Request; Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

22. Fuel Flow Meter: A fuel flow meter shall be installed on the biomass boiler to record the amount of fossil fuel (ULSD fuel oil or propane) used in the boiler on a hourly, monthly and 12 month rolling average basis.
[Rule 62-4.070(3), Reasonable Assurance]

23. SNCR, SCR or SNCR/SCR Combination Urea or NH_3 Injection Rate: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea or NH_3 injection rate for the SNCR, SCR or SNCR/SCR combination system for the biomass boiler. The permittee shall document the general range of urea or NH_3 flow rates required to meet the NO_X standard over the range of load conditions by comparing NO_X emissions with urea or NH_3 flow rates. During NO_X CEMS downtimes or malfunctions, the permittee shall operate at a urea or NH_3 flow rate that is consistent with the documented flow rate for the given load condition. Urea or NH_3 injection records shall be maintained on site and made available upon request.
[Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

RECORDS AND REPORTS

24. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (mmBtu/hour), calculated authorized fuels firing rate (tons/hour, gallons per hour and cubic feet per minute as appropriate), and emission rates (lb/mmBtu, ppmvd @ 7% oxygen and lb/hr as appropriate). Results from any HCl emission rate stack tests conducted during the period addressed by the stack test report shall be included. [Rule 62-4.070(3), F.A.C.]

25. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following parameters for the biomass boiler in a written or electronic log for the previous month of operation: hours of operation, tons of sweet sorghum bagasse, tons of wood chips and cubic feet of biogas, pounds of steam, total heat input rate and the updated 12-month rolling totals for each of these operating parameters. Cubic feet of propane or gallons of ULSD fuel oil used shall be recorded in a written or electronic log for the previous month of operation along with the updated 12-month rolling totals for each of these fossil fuels. In addition, the hourly heat input rate to the biomass boiler shall be recorded and reported. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Quarterly CO, NO_X, SO_2 and HCl and Opacity Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO, NO_X, SO_2, HCl and opacity emissions including periods of startups, shutdowns, malfunctions, and CEMS and COMS systems monitor availability for the previous quarter. If opacity COMS data is excluded from a compliance determination during the quarter due to a startup, shutdown or malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See Appendix CTR of this permit for the reporting format.
[Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

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C. Cooling Towers (EU-003)

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
003	*Cooling Towers*: The SRF facility will have three mechanical draft cooling towers. One cooling tower, the machine cooling tower, will consist of a single cell used to cool miscellaneous machinery. A condensing set cooling tower, containing three cells, will be used to cool water coming from the power house condensing set. A third cooling tower also consisting of three cells will be used for cooling of process equipment used in ethanol production. [Application No. 0510032-001-AC]

EQUIPMENT

1. Machine Cooling Tower (Cooling Tower No. 1): The permittee is authorized to install one new 1-cell mechanical draft cooling tower with a design height of 35 ft, a circulating water flow rate of 3,434 gallons per minute (gpm) at a temperature of 77 °F and shall have a design drift rate of 0.001% to provide cooling to miscellaneous machinery at the SRF facility.

2. Condensing Set Cooling Tower (Cooling Tower No. 2): The permittee is authorized to install one new 3-cell mechanical draft cooling tower with a design height of 35 feet, a circulating water flow rate of 17,962 gpm at a temperature of 77 °F and shall have a design drift rate of 0.001% to provide cooling to the power house condensing set at the SRF facility.

3. Ethanol Process Equipment Cooling Tower (Cooling Tower No. 3): The permittee is authorized to install one new 3-cell mechanical draft cooling tower with a design height of 35 feet, a circulating water flow rate of 17,962 gpm at a temperature of 77 °F and shall have a design drift rate of 0.001% to provide cooling to ethanol production process equipment at the SRF facility.

[Application No. 0510032-001-AC and Rule 62-210.200 (PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year). [Application No. 0510032-001-AC and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Total Dissolved Solids (TDS): The makeup water used in the cooling towers may contain no more than 1,000 parts per million by weight (ppmw) of TDS. The makeup water in each cooling tower must be tested weekly for TDS. Records of each test must be kept on site and made available to the Compliance Authority upon request. [62-4.070, F.A.C. Reasonable Assurance]

EMISSIONS STANDARDS

6. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling towers were constructed to achieve the specified drift rate of no more than 0.001% of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

7. VOC Emissions: The permittee shall control VOC emissions by promptly repairing any leaking components in accordance with the approved LDAR plan. The permittee shall collect a sample of cooling water on a weekly basis from cooling towers No. 1 and No. 3 and analyze it for VOCs to enable the early detection of leaking heat exchangers and thereby minimizing VOC emissions from the cooling towers. [Application No. 0510032-001-AC; Rules 62-210.200 (PTE), 62-212.400(BACT) and 62-4.070, F.A.C. Reasonable Assurance; 40 CFR 60 NSPS, Subpart VVa]

   {Permitting Note: These work practice standards are established as BACT for $PM_{10}/PM_{2.5}$ and VOC emissions from the cooling towers.}

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C. Cooling Towers (EU-003)

TESTING AND MONITORING REQUIREMENTS

8. VOC Cooling Water Monitoring Plan: A monitoring plan detailing how the cooling tower water shall be monitored for VOC contamination from leaking heat exchangers as required by **Specific Condition 7** above shall be submitted to the compliance authority for approval no later than 180 days before the SRF facility becomes operational.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

9. VOC Water Testing Frequency: Testing of the cooling water shall be conducted weekly unless VOC contamination is found during one of the weekly tests. Then daily testing will be required until the mechanical leak is corrected and no VOC contamination is detected in the cooling tower water.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

10. Notification: The permittee shall notify the Compliance Authority in writing within 24 hours when any VOC contamination of the cooling tower water is discovered. Additionally, the permittee shall submit a plan to correct the problem within 7 days for the approval of the Compliance Authority.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

RECORDS AND REPORTS

11. Monitoring Test Reports: The permittee shall prepare and submit reports for all required monitoring tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit, including descriptions of any VOC contamination discovered and the corrective action taken.
[Rule 62-297.310(8), F.A.C.]

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D. Ethanol Production Process (EU-004)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
004	Ethanol Production Process: The maximum design ethanol production rate is 67,000 gallons per day (gpd) and 22.11 mgpy. This emission unit consists of the following major processes: *Juice Extraction, Treatment and Evaporation*: The evaporation process concentrates sweet sorghum sucrose juices extracted in the diffuser. The extracted juice is pumped from the storage tank to several juice heaters and two evaporators where it is heated until it evaporates the water. The juice is gradually concentrated to form syrup during the evaporation process. *Fermentation*: Yeast is used to produce ethanol from hexoses (6-carbon sugars). This process is commonly known as fermentation. Fermentation consists of several steps: mash preparation, yeast treatment and fermentation. Concentrated juice from the evaporation process is pumped into the fermenter vessels. As an alternative, sweet sorghum molasses can also be utilized in the process. During fermentation, sugars contained in the mash are transformed to ethyl alcohol, carbon dioxide (CO_2) and various secondary products. Secondary products include other alcohols, aldehydes, glycerin, etc. The alcohol concentration in the clean beer is generally 8%. The off-gases from the fermentation vessels, which contain primarily CO_2 and ethanol with minor traces of other organic compounds, are collected and sent to a washing column. CO_2, free from alcohol, is released to the atmosphere or will be sent to an adjacent dry ice plant for recovery. *Distillation*: Hydrated alcohol is produced using an atmospheric distillation module with four columns. From fermentation, clean beer with an alcohol concentration of approximately 8% is sent to distillation. The beer may contain many other liquid, solid, and gaseous components. Liquid components include water at 89% to 93% and finer alcohols, acetic aldehyde, succinic acid, acetic acid, furfural, etc., at lower concentrations. Ethyl alcohol present in the beer is extracted by distillation in columns. Hydrated alcohol at 96% concentration is extracted in the vapor phase from the top of the distillation columns, cooled in a plate-type heat exchanger, and transferred to a storage tank in the dehydration section. *Dehydration*: The final stage in the ethanol production process is dehydration. Hydrated alcohol from the distillation process undergoes dehydration with a molecular sieve to produce ethanol at 99.67% purity.

EQUIPMENT

The permittee is authorized to construct the following equipment used during the production of ethanol and to control VOC emissions from the process:

1. Juice Extraction: The permittee is authorized to construct the following major components of a juice extraction system: two sets of revolving sorghum high efficiency knives; one heavy-duty shredder; one high speed belt conveyor; one fixed-bed horizontal diffuser; various juice receivers; four juice heaters; two rotary screens; one lime mixing tank; two pre-drying rolls; one four-roll drying mill; and one juice tank.
2. Juice Treatment and Evaporation: The permittee is authorized to construct the following major components of a juice treatment and evaporation system: one juice regenerator (heater); primary heaters and secondary heaters; one juice evaporator; two concentrated juice tanks; and clean and foul condensate tanks.
3. Mash Preparation, Yeast Treatment and Fermentation: The permittee is authorized to construct the following major components of a mash preparation, yeast treatment and fermentation system: a sulfuric acid tank; one mash cooler; one wine cooler; one yeast treatment tank; seven fermenters; one beer tank; one beer filter; two yeast centrifuges; one beer buffet tank; and one CO_2 scrubbing column.

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4. Distillation: The permittee is authorized to construct the following major components of a distillation system: one distillation column; one degassing column; one heads concentrate column; one rectification column; one fusel oil decanter; one hydrated alcohol tank; one CO_2 washing column.
5. Dehydration: The permittee is authorized to construct the following major components of a dehydration system: one hydrated alcohol heater; two zeolite absorber (molecular sieve) vessels; condensers and coolers; one dehydrated alcohol holding tank; on permeate collector tank; and one CO_2 washing column.
6. Dry Ice Plant: The permittee is authorized to construct a Dry Ice Plant at the SRF Facility. The plant will utilize the CO_2 off gas from the ethanol production process to manufacture dry ice.
7. Air Pollution Control Equipment: The permittee shall install three wet scrubbers to control VOC emissions from the fermentation, distillation and dehydration systems. The wet scrubbers shall have a design control efficiency of 98%. Emissions from the wet scrubbers shall discharge through a wet scrubber stack with a design height of 25 ft (minimum), a design diameter of 4.9 ft (maximum) at a design exit temperature of 70 °F and flow rate of 4,223 acfm.

[Application No. 0510032-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

8. Hours of Operation: The hours of operation of the ethanol production process are limited to 8,400 hours in any consecutive twelve month period. [Application No. 0510032-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

9. VOC Standard: The ethanol process emission unit shall not discharge VOC through the wet scrubber stack in excess of 10.20 lb/hr (42.3 TPY). [Application No. 0510032-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]
10. HAP Standard: The ethanol process emission unit shall not discharge organic HAP through the wet scrubber stack in excess of 0.87 lb/hr (3.45 TPY). [Application No. 0510032-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

TESTING REQUIREMENTS

11. Initial Compliance Tests: The wet scrubber stack shall be tested to demonstrate initial compliance with the emissions standard for VOC and HAP given in **Specific Conditions 9 and 10**, respectively above. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance; 62-210.200(PTE); and 62-297.310(7)(a)1, F.A.C.]
12. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the wet scrubber stack shall be tested to demonstrate compliance with the emissions standard for VOC and HAP given in **Specific Conditions 9 and 10**, respectively above. [Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance; 62-210.200(PTE); and 62-297.310(7)(a)4, F.A.C.]
13. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

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14. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 320	Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

The above methods are described in Appendix A of 40 CFR 60 and are 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 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

MONITORING REQUIREMENTS

15. Wet Scrubbers Monitoring Requirements:
    a. Scrubbers Operating Parameters: The permittee shall install, calibrate, operate and maintain monitoring devices that continuously measure and record the total pressure drop across each scrubber. If the total pressure drop cannot be measured for the scrubber, then the liquid flow rate and the fan amps shall be measured and recorded for the scrubber. Accuracy of the monitoring devices shall be ± 5% over the operating range.
    b. Scrubbers Guarantee: Prior to installation of the scrubber, the permittee shall submit to the Compliance Authority the proposed design information along with a manufacturer's guarantee that the scrubbers are capable of meeting the emission limitations established by the VOC BACT determination.

    [Rule 624.070(3), F.A.C.; Rule 62-297.310 and Rule 62-212.400, F.A.C.]

RECORDS AND REPORTS

16. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]
17. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of ethanol produced on a daily, monthly and 12 month rolling average basis along with the feed rate (sweet sorghum, sweet sorghum syrup and molasses) into the ethanol production process emission unit on a monthly basis and 12 month rolling average basis. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

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E. Bioreactors and Biogas Flare (EU-005)

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
005	Bioreactors and Biogas Flare: The SRF facility will include bioreactors to treat process wastewaters and to condition the resulting biogas for use as fuel in the biomass boiler or to flare it when it cannot be used in the boiler. During ethanol production, wastewaters from production are collected and treated in the bioreactors to reduce the chemical and biological oxygen demand prior to discharging the waters.

EQUIPMENT

1. The permittee is authorized to construct a biodigester system consisting of the following major pieces of equipment:
   - Two methane bioreactors for treatment of wastewater;
   - One degas tank; and
   - One flare to combust the biogas generated from the bioreactors when the biomass boiler is not available.

   [Application No. 0510032-001-AC]
2. Biogas Flare System: The permittee shall construct one flare system with a continuous pilot and combustion chambers to combust the biogas from the bioreactors when the biomass boiler is not available. The flare shall be operated with a flame present at all times. 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. [Application No. 0510032-001-AC; and Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]
3. Biogas Scrubber: The permittee shall design, install, operate, and maintain a wet scrubber to remove H_2S from the biogas from the bioreactors prior to combustion in the biogas flare system. The biogas scrubber shall have a control efficiency of at least 98%. The biogas scrubber shall be on line and functioning properly whenever the biogas flare system is in operation. [Application Request; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Approximate Flare Capacity: The biogas flare system shall only combust biogas when the biomass boiler is not operating, or when the biomass boiler is in startup or shutdown mode. The flare will have a rated capacity of combusting 38,000 standard cubic feet per hour (scf/hr) of biogas which is equivalent to a heat input rate of 27.55 mmBtu/hr. Natural gas or propane will be used as fuel for the pilot. [Application No. 0510032-001-AC and Rule 62-210.200(PTE), F.A.C.]
5. Required Operation: The biogas flare shall be operated at all times when all the biogas generated by the bioreactors cannot be combusted in the biomass boiler. [Application No. 0510032-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
6. Hours of Operation: The hours of operation of the biogas flare system is limited to 720 hours per year. [Application No. 0510032-001-AC and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

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NSPS SUBPART A APPLICABILITY

7. General Control Device Requirements: The biogas flare associated with this emission unit must meet all applicable requirements of 40 CFR §60.18, General Control Device Requirements. [NSPS Subpart A and Rule 62-4.070(3), F.A.C.]

EMISSIONS STANDARDS, TESTING AND MONITORING REQUIREMENTS

8. VE Standard: The flare shall be designed for and operated with no visible emissions (VE) except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [NSPS 40 CFR 60, Subpart A and Rule 62-4.070(3), F.A.C.]

9. H_2S Biogas Standard and Testing: Three samples of biogas entering (inlet) and exiting (outlet) the scrubber shall be taken every calendar quarter and tested for H_2S concentration in ppm. The control efficiency of the scrubber shall be determined as indicated below and must be 98% or greater based on the arithmetic average of the 3 samples from each calendar quarter.

Where: = H_2S inlet concentration in ppm
= H_2S outlet concentration in ppm

10. VE Compliance Tests: The flare system exhaust shall be tested to demonstrate initial compliance with the VE standard given in **Specific Condition 8** above no later than 180 days after initial operation and during each federal fiscal year (October 1st to September 30th) thereafter. EPA Method 22 VE compliance test(s) shall be used to determine the compliance of the flare with the visible emission requirements. The observation period is 2 hours and shall be used according to Method 22. The flare performance test shall be when ethanol is being loaded into trucks that previously held gasoline. [Rule 62-4.070(3), F.A.C.]

11. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
EPA 15	Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions From Stationary Sources
EPA 22	Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares 2 Hour Duration

13. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare system are minimized. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of this system in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. The flare pilot shall be operated with a flame present at all times. [Rules 62-4.070(3) F.A.C.]

14. Biogas Scrubbers Monitoring Requirements:

    a. *Scrubber Operating Parameters*: The permittee shall install, calibrate, operate and maintain monitoring devices that continuously measure and record the total pressure drop across the biogas scrubber. If the total pressure drop cannot be measured for the scrubber, then the liquid flow rate and the fan amps shall be measured and recorded for the scrubber. Accuracy of the monitoring devices shall be ± 5% over the operating range.

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b. *Scrubber Guarantee*: Prior to installation of the scrubber, the permittee shall submit to the Compliance Authority the proposed design information along with a manufacturer's guarantee that the scrubbers are capable of meeting the emission limitations established in this permit.
[Rule 624.070(3), F.A.C.; Rule 62-297.310 and Rule 62-212.400, F.A.C.]

RECORDS AND REPORTS

15. Records: The permittee shall record in a written log the duration of each flare event and the reason for flaring. If requested by the Compliance Authority, the permittee shall provide a copy of these records or a summary of these records. [Rule 62-4.070(3), F.A.C.]

16. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit.
[Rule 62-297.310(8), F.A.C.]

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F. Storage Tanks (EU-006)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
006	Storage Tanks: This emissions unit consists of: the five tanks involved in the ethanol and gasoline blending and storage which results in the denatured ethanol final product; the five tanks that are involved in the ethanol production process; the ammonia or urea storage tank used for the SCR/SNCR system(s); the ULSD fuel oil tank; and the sulfuric acid storage tank.

Tanks will be used during the ethanol production process to store ethanol, byproducts and intermediate products. In addition, the purified ethanol and gasoline (denaturant) will be stored in tanks and then blended, resulting in a product that contains approximately 10% or 85% ethanol and 90% or 15% gasoline by volume with the resulting blended product commonly called E10 or E85. The denatured ethanol product will have dedicated storage tanks. Anhydrous ammonia or urea will be stored in a tank for use in the SCR/SNCR system(s) for the boiler NO_X control. ULSD fuel oil will be stored in a tank for use in the boiler as a startup, shutdown and bed stabilization fuel.

EQUIPMENT

1. The permittee is authorized to construct the following tanks to store volatile organic liquids (VOL):
   a. *Blending and Storage Tanks*:
      - Final Product Ethanol Tanks: The permittee is authorized to construct two nominal 875,000 gallons ethanol product storage tanks with fixed roofs and internal floating roofs to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
      - Second Grade Alcohol Product Storage Tank: The permittee is authorized to construct a nominal 153,220 gallon denatured/gasoline storage tanks with fixed roofs and internal floating roofs to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
      - Denatured /Gasoline Product Storage Tank: The permittee is authorized to construct a nominal 250,000 nominal gallon denatured/gasoline storage tank with a fixed roof and an internal floating roof to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
      - Blend Storage Tank: The permittee is authorized to construct a nominal 50,000 gallon product storage tank with a fixed roof and an internal floating roof to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
   b. *Ethanol Production Process Tanks*:
      - Fusel Oil Storage Tank: The permittee is authorized to construct one nominal 47,551 gallon fusel oil storage tank.
      - Hydrated Alcohol Storage Tank: The permittee is authorized to construct one nominal 2,642 gallon hydrated oil storage tank.
      - Final Product Metering Tank: The permittee is authorized to construct one nominal 7,925 gallon metering storage tank.
      - Second Grade Alcohol Storage Tank: The permittee is authorized to construct one nominal 2,642 gallon second grade storage tank.
      - Fusel Oil Alcohol Storage Tank: The permittee is authorized to construct one nominal 1,849 gallon fusel oil storage tank.
   c. *Other Tanks*:
      - Anhydrous Ammonia or Urea Storage Tank: The permittee is authorized to construct a nominal 5,000 gallon tank to store anhydrous ammonia or urea for the SCR/SNCR system(s). In accordance with 40 CFR 60.130, the storage of anhydrous ammonia or urea shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

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- ULSD Fuel Oil Storage Tank: The permittee is authorized to construct a nominal 50,000 gallon tank to store ULSD fuel oil for use as a biomass boiler fuel for startup, shutdown and flame (bed) stabilization.
- ULSD Fuel Oil Storage Tank: The permittee is authorized to construct a nominal 5,000 gallon tank to store ULSD fuel oil for use in emergency equipment.
- Sulfuric Acid Storage Tank: The permittee is authorized to construct a tank to store sulfuric acid for use in the mash preparation, yeast treatment and fermentation. In accordance with 40 CFR 60.130, the storage of sulfuric acid shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Application No. 0510032-001-AC]

PERFORMANCE RESTRICTIONS

2. Permitted Capacity: The maximum throughput (process) rate in gallons per year for this emissions unit is 23.01 million gallons of denatured ethanol product in any consecutive twelve month period. [Application No. 0510032-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

3. Hours of Operation: The hours of operation of this emissions unit are not restricted (8,760 hours per year). [Application No. 0510032-001-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS SUBPART Kb APPLICABILITY

4. VOL Blending and Storage Tanks: The five Blending and Storage tanks at the SRF facility are subject to NSPS Subpart Kb which applies to any storage tank for which construction, reconstruction, or modification is commenced after July 23, 1984 with a capacity greater than or equal to 151 cubic meters (m^3) or 39,990 gallons that is used to store a VOL with a maximum true vapor pressure greater than or equal to 3.5 kilopascals (kPa) or 0.51 pounds per square inch (psi). The five Blending and Storage tanks each have a capacity greater than 40,000 gallons and store liquids with maximum true vapor pressures greater than 3.5 kPa and consequently are subject to and must comply with the provisions of NSPS 40 CFR 60, Subpart Kb.

5. VOL Ethanol Production Process, Ammonia/Urea and Sulfuric Acid Storage Tanks: The five Ethanol Production Process storage tanks, the ammonia or urea storage tank and the sulfuric acid storage tank at the SRF facility are not subject to NSPS Subpart Kb. These tanks are exempt because either they have a capacity less than 75 m^3 or 19,813 gallons or they have a capacity greater than or equal to 19,813 gallons but less than 39,990 gallons (151 m^3) and store a liquid with a maximum true vapor pressure less than 15 kPa (2.18 psi).

6. ULSD Fuel Oil Storage Tank: The ULSD fuel oil storage tank at the SRF facility is not subject to NSPS Subpart Kb because it is larger or equal to 40,000 gallons (151 cubic meters) and stores a liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psi).

EMISSIONS STANDARDS

7. VOC Standard for Blending and Storage Tanks: Emissions of VOC from the Blending and Storage tanks will be controlled by the proper construction of the tanks per 40 CFR 60.110b(a)(2) which requires internal floating roofs in the tanks or the equivalent.
[Application No. 0510032-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

8. Pressure Relief Valves: In lieu of internal floating roofs in the Blending and Storage tanks, SRF may use pressure relief valves provided that these meet the equivalency requirements of NSPS, Subpart Kb. If SRF decides to use pressure relief valves in lieu of internal floating roofs, it must provide to the Compliance Authority 90 days before construction of the Blending and Storage VOL tanks commences, proof of the valves equivalency as defined in the NSPS.

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[Application No. 0510032-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

9. VOC Standard for Ethanol Production Process Storage Tanks: Emissions of VOC from the Ethanol Production Process storage tanks will be controlled by the use of pressure relief valves or vapor condensers. [Application No. 0510032-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

RECORDS AND REPORTS

10. Storage Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage tanks and an analysis showing the capacity of the storage tanks. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of the various liquids for the storage tanks for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

11. NSPS Subpart Kb Reporting and Recordkeeping for Blending and Storage Tanks: The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of §60.115b Reporting and Recordkeeping Requirements. The owner or operator shall keep copies of all reports and records required by§60.115b, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment. [Rule 62-4.070(3) F.A.C and NSPS 40 CFR 60, Subpart Kb]

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G. Truck Rack Product Loadout and Flare (EU-007)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
007	Truck Rack Product Loadout and Flare: The denatured blended ethanol product from VOL Blending and Storage tanks will be loaded out to tanker trucks with displaced vapors sent to a product loadout flare for destruction.

The denatured ethanol product will be loaded onto tank trucks at a maximum rate of 600 gpm. Vapors displaced from the trucks will be combusted by a product loadout flare. The product loadout flare will have a nominal rated heat input capacity of 9.8 mmBtu/hr to control vapors displaced from the tanker trucks during the loading of the denatured ethanol product. The flare will have a design control efficiency of 99%.

EQUIPMENT

1. Loading Rack: The permittee is authorized to construct a loading rack that is designed to transfer 600 gpm of denatured ethanol product to tanker trucks.
   [Application No. 0510032-001-AC and 62-210.200(PTE), F.A.C.]

2. Flare System: The permittee is required to construct one flare system with a continuous pilot and combustion chambers to destroy displaced vapors during truck loadout. The flare shall be operated with a flame present at all times. 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.
   [Application No. 0510032-001-AC and 62-210.200(PTE), F.A.C.]

3. Fueling Station: The permittee is authorized to construct a Fueling Station at the SRF Facility. The station will dispense the denatured ethanol product and E10/E85 blended products to SRF and to sweet sorghum farming-related vehicles. [Application No. 0510032-001-AC and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Approximate Capacities: The flare system is designed to combust vapors displaced from the trucks during the loading of the denatured ethanol product. The trucks are assumed to not be in dedicated denatured ethanol product service (i.e., some trucks will have returned from delivering gasoline and gasoline vapors will be displaced). The product loadout flare will have a rated capacity of 9.8 mmBtu/hr. Natural gas or propane will be used as the fuel for the pilot flame.
   [Application No. 0510032-0010-AC and Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The flare shall be operated at all times when truck loading operations are taking place. Only E10 or E85 shall only be loaded into the trucks. Although the hours of operation of the pilot for the flare system are not limited (8,760 hours per year) the flare itself is limited to 3,120 hours per year.
   [Application No. 0510032-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

6. VE Standard: The flare shall be designed for and operated with no visible emissions (VE) except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.
   [Rule 62-4.070(3), F.A.C.; NSPS 40 CFR 60, Subpart A]

NSPS SUBPART A APPLICABILITY

7. General Control Device Requirements: The product loadout flare associated with this emission unit must meet all applicable requirements of §60.18, General Control Device Requirements.
   [NSPS Subpart A and Rule 62-4.070(3), F.A.C.]

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TESTING AND MONITORING REQUIREMENTS

8. VE Compliance Tests: The flare system exhaust shall be tested to demonstrate initial compliance with the VE standard given in **Condition 6** above no later than 180 days after initial operation and during each federal fiscal year (October 1st to September 30th) thereafter. EPA Method 22 VE compliance test(s) shall be used to determine the compliance of the flare with the visible emission requirements. The observation period is 2 hours and shall be used according to Method 22. The flare performance test shall be when ethanol is being loaded into trucks that previously held gasoline. [Rule 62-4.070(3), F.A.C.]

9. 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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
EPA 22	Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares 2 Hour Duration

11. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare system are minimized. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of this system in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. The flare pilot shall be operated with a flame present at all times. [Rules 62-4.070(3) F.A.C.]

RECORDS AND REPORTS

12. Records: The permittee shall record in a written log the duration of each flare event and the reason for flaring. If requested by the Compliance Authority, the permittee shall provide a copy of these records or a summary of these records. [Rule 62-4.070(3), F.A.C.]

13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]

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H. Miscellaneous Storage Silos (EU-008)

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
008	Miscellaneous Storage Silos: Silos at SRF to store lime for the wastewater treatment and DSIS systems; limestone and sand for the BFB boiler (if used); urea (if used); and fly ash from the boiler.

The SRF will include equipment and silos for the handling and storage of dry materials.

CONSTRUCTION

1. Equipment: The permittee is authorized to construct the following silos each with a baghouse (bin vent filters) to control PM emissions:
   - One lime storage silo for the DSIS;
   - One lime storage silo for the wastewater treatment system;
   - If used in SNCR/SCR system(s), one urea storage silo;
   - One limestone storage silo, if a BFB boiler is used;
   - One sand storage silo, if a BFB boiler is used; and
   - Fly ash storage silo.

   [Application No. 0510032-001-AC]

PERFORMANCE RESTRICTION

2. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year). [Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

EMISSIONS STANDARDS

3. PM Standard: PM emissions from each baghouse of the silos shall not exceed 0.01 gr/dscf. [Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

4. VE Standard: VE from the silo baghouses shall not exceed 5% opacity as demonstrated by initial and annual compliance tests. A visible emission reading of 5% opacity or less may be used to establish compliance with the PM emission standard in Specific **Condition 3** above**.** A visible emission reading greater than 5% opacity will require the permittee to perform a PM emissions stack test within 60 days to show compliance.
   [Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

TESTING AND MONITORING REQUIREMENTS

5. Initial Compliance Tests: Each silo shall be tested to demonstrate initial compliance with the VE emissions standard specified in **Condition 4** above. The initial test shall be conducted within 180 days after initial operation.
   [Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

6. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each silo shall be tested to demonstrate compliance with the VE emissions standard specified in **Condition 4** above.
   [Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

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7. PM Compliance Test: The initial and annual VE tests in **Conditions 5 and 6** above shall serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Condition 4** above is not met, PM tests utilizing EPA Method 5 must be conducted within 60 days on the silo bin vent filters to show compliance with the PM emissions standard in **Condition 3** above.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

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 CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

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

Method	Description of Method and Comments
EPA 5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
EPA 9	Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources 60 Minute Test

RECORDS AND REPORTS

10. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

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I. Two Emergency Generators (EU-009)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
009	Two emergency generators each rated at 2,000 kilowatts (kW) or 2,682 horsepower (Hp)

Two emergency generators, each rated at 2,000 kW, will be installed to provide backup electrical power in the event of a power outage at the SRF facility. The engines will fire ULSD fuel oil or propane and each will be limited to 500 hours per year of operation during emergencies. Each unit will be operated no more than 100 hours per year for testing and maintenance purposes per 40 CFR 60, Subpart IIII. Each engine will be designed to meet USEPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2006 or later.

EQUIPMENT

1. Emergency Generators: The permittee is authorized to install, operate, and maintain two 2,000 kW or less emergency generators. [Application No. 0510032-001-AC and Rule 62-210.200 (PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Hours of Operation: Each emergency generator may operate in response to emergency conditions for up to 500 hours per year and 100 non-emergency hours per year for generator maintenance and testing purposes. The duration of any one maintenance action or test is limited to 30 consecutive minutes.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C. and NSPS 40 CFR 60, Subpart IIII]

3. Authorized Fuel: These units shall fire ULSD fuel oil or propane. The ULSD fuel oil shall contain no more than 0.0015% sulfur by weight.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C. and NSPS 40 CFR 60, Subpart IIII]

EMISSION STANDARDS

4. Emissions Limits: Each emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in NSPS 40 CFR 60, Subpart IIII the language of which is given in Appendix IIII. Manufacturer certification can be provided to the Department in lieu of actual stack testing.

Source (model year)	CO (g/KW-hr)	PM (g/KW-hr)	Hydrocarbons (g/KW-hr)	NO_X (g/KW-hr)
Subpart IIII (2006 and later)	3.5	0.20	6.4 (NMHC[a]+NO_X)	

a. NMHC means Non-Methane Hydrocarbons.

[Application No. 0510032-001-AC; NSPS 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

5. Notification, Recordkeeping and Reporting Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

NSPS APPLICABILITY

6. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

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NESHAP APPLICABILITY

7. NESHAPS Subpart ZZZZ Applicability: These emergency generators are a Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the generators must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

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J. Emergency Diesel Fueled Fire Pump Engine (EU-010)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
010	One emergency diesel fire pump engine rated at 600 hp (448 kW)

A 600 hp diesel fire pump engine will be installed to provide firewater during power outages. This unit will fire ULSD fuel oil or propane and will be limited to 500 hours per year of operation. This unit will be operated no more than 100 hours per year for testing and maintenance purposes per 40 CFR 60, Subpart IIII. The engine will be designed to meet USEPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2009 or later.

EQUIPMENT

1. Diesel Engine Driven Fire Pump Engine: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump engine of 600 hp or less.
[Application No. 0510032-001-AC and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Hours of Operation: The fire pump engine may operate in response to emergency conditions for up to 500 hours per year and 100 non-emergency hours per year for fire pump engine maintenance and testing The duration of any one maintenance action or test is limited to 30 consecutive minutes.
[Application No. 0510032-001-AC; Rule 62-210.200 (PTE), F.A.C. and NSPS 40 CFR 60, Subpart IIII]

3. Authorized Fuel: This unit shall fire ULSD fuel oil or propane. The ULSD fuel oil shall contain no more than 0.0015% sulfur by weight. [Application No. 0510032-001-AC and Rule 62-210.200 (PTE), F.A.C. and NSPS 40 CFR 60, Subpart IIII]

EMISSION STANDARDS

4. Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in NSPS 40 CFR 60, Subpart IIII. Manufacturer certification may be provided to the Department in lieu of actual testing.
[40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

Model Year	CO (g/hp-hr)	NMHC + NO_X (g/hp-hr)	PM (g/hp-hr)
Subpart IIII (2009 or later)	2.6	3.0	0.15

[Application No. 0510032-001-AC and 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

5. Notification, Recordkeeping and Reporting Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

NSPS APPLICABILITY

6. NSPS Subpart IIII Applicability: The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.
[40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

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NESHAP APPLICABILITY

7. NESHAPS Subpart ZZZZ Applicability: The fire pump engine is a Liquid Fueled Reciprocating Internal Combustion Engine (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the fire pump engine must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

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K. Facility-Wide Fugitive VOC Emission Leaks (EU-011)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
011	Facility-Wide Fugitive VOC Emission Leaks: This emission unit consists of the fugitive VOC emissions from equipment leaks involved in the ethanol production process and associated processes at the SRF facility. Total fugitive VOC emissions from equipment leaks at the SRF facility were estimated to be 6.52 TPY. To minimize VOC fugitive emissions, SRF shall implement a monthly leak detection and repair (LDAR) program. The plan to implement the LDAR program shall be approved by the Compliance Authority in accordance with New Source Performance Standard (NSPS) 40 CFR Part 60, Subpart VVa. The following emission units are either subject to the requirements of NSPS 40 CFR Part 60, Subpart VVa and must be addressed in the LDAR program plan or addressed by the plan has part of the BACT to minimize emissions of VOC from the SRF facility: • *EU-002: Cogeneration Biomass Boiler , i.e., biogas feed system to boiler;* • *EU-003: Cooling Towers;* • *EU-004: Ethanol Production Process;* • *EU-005: Bioreactors and Biogas Flare;* • *EU-006: Storage Tanks; and* • *EU-007: Truck Rack Product Loadout and Flare.*

NSPS SUBPART VVa

1. Leak Detection and Repair (LDAR) Program: SRF is subject to NSPS 40 CFR 60, Subpart VVa - VOC Equipment Leaks in the Synthetic Chemical Manufacturing Industry (SOCMI), for projects that commence construction or modifications after November 7, 2006. NSPS Subpart VVa requires a LDAR program. SRF must demonstrate compliance with Subpart VVa, including the LDAR program, no later than 180 days after SRF becomes operational.
   [40 CFR 60, Subpart VVa and Rule 62-4.070, F.A.C. Reasonable Assurance]

2. Equipment Subject to NSPS, Subpart VVa: As per **Condition 12** of Section II of this permit, a list of all the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves at SRF that are subject to NSPS Subpart VVa must be submitted to the Compliance Authority no later than 90 days prior to commencing operation.
   [Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

TESTING AND MONITORING REQUIREMENTS

3. LDAR Program Plan Implementation: As per **Condition 11** of Section II of this permit, the permittee must submit for approval a LDAR program plan no later than 90 days prior to commencing operation. Once the program plan is approved by the Compliance Authority, the permittee shall implement the program within 180 days of initial startup of the SRF. [40 CFR 60, Subpart VVa ; Application No. 0510032-001-AC; Rule 62-210.200(PTE), F.A.C. and Rule 62-4.070(3), F.A.C. Reasonable Assurance]

4. Compliance with NSPS VVa: The permittee shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment subject to NSPS Subpart VVa within 180 days of initial startup of the SRF. [Application No. 0510032-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

5. Test Methods and Procedures: The permittee shall show the SRF is in compliance with the requirements of NSPS Subpart VVa following the test methods and procedures specified in §60.485a.

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[Application No. 0510032-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

RECORDS AND REPORTS

6. NSPS VVa Recordkeeping Requirements: The permittee shall follow the recordkeeping requirements specified in §§60.486a to show compliance with NSPS Subpart VVa and submit the records to the Compliance Authority 180 days after the initial startup of the SRF and annually thereafter. [Application No. 0510032-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

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Appendix ASME:	American Society of Mechanical Engineers (ASME) Form for Abbreviated Efficiency Test.
Appendix BMP:	Best Management Practices.
Appendix CC:	Common Conditions.
Appendix CEMS:	Continuous Emissions Monitoring System (CEMS) Requirements.
Appendix CF:	Citation Formats and Glossary of Common Terms.
Appendix CTR:	Common Testing Requirements.
Appendix Db:	NSPS, Subpart Db – Standards of Performance Small Industrial-Commercial-Institutional Steam Generating Units.
Appendix Eb:	NSPS, 40 CFR 60, Subpart Eb – Standards of Performance for Large Municipal Waste Combustors.
Appendix F:	40 CFR 75, Appendix F, Section 5 - Measurement of Boiler Heat Input Rate.
Appendix GC:	General Conditions.
Appendix-GP:	Identification of General Provisions, Subpart A from NSPS 40 CFR 60 and Subpart A from NESHAP 40 CFR 63.
Appendix IIII:	NSPS, Subpart IIII - Stationary Compression Ignition Internal Combustion Engines.
Appendix Kb:	NSPS, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels.
Appendix LDAR:	Preliminary Leak Detection and Repair (LDAR) Program.
Appendix VVa:	NSPS, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the SOCMI.
Appendix ZZZZ:	NESHAP, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines (RICE).

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AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME) FORM FOR ABBREVIATED EFFICIENCY TEST

Below is the form from the American Society of mechanical Engineers (ASME) that may be used by SRF, with concurrence of the Compliance Authority, to calculate the heat input rate (mmBtu/hr) into the biomass boiler as required by **Specific Condition 4 of Subsection 3-B** of this permit.

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AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME) FORM FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-b (1964)

CALCULATION SHEET — ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST — *Revised September, 1965*

OWNER OF PLANT | TEST NO. | BOILER NO. | DATE

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = ... kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$

CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43}}{100} - \left[\frac{\text{ITEM 22} \times \text{ITEM 23}}{14{,}500}\right]$ = ...

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S)

$$= \frac{11 \times \text{ITEM 32} + 8 \times \text{ITEM 33} + 7\left(\text{ITEM 35} + \text{ITEM 34}\right)}{3 \times \left(\text{ITEM 32} + \text{ITEM 34}\right)} \times \left[\text{ITEM 24} + \frac{\text{ITEM 47}}{267}\right] = \ldots\ldots$$

36 EXCESS AIR † $= 100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})} = \ldots\ldots$

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = ITEM 25 × 0.24 (ITEM 13) − (ITEM 11) = ... (Unit)	.....	$\frac{65}{41} \times 100 =$	.....
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	.....	$\frac{66}{41} \times 100 =$	.....
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	.....	$\frac{67}{41} \times 100 =$	.....
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 × ITEM 23 = ...	.....	$\frac{68}{41} \times 100 =$	.....
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	.....	$\frac{69}{41} \times 100 =$	.....
70	UNMEASURED LOSSES **	.....	$\frac{70}{41} \times 100 =$	.....
71	TOTAL	.....	.....	.....
	EFFICIENCY = (100 − ITEM 71)	.....	.....	.....

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

PRELIMINARY BEST MANAGEMENT PRACTICES (BMP) PLAN FOR MINIMIZATION OF FUGITIVE DUST, PILE MANAGEMENT AND FIRE PREVENTION

The permittee shall comply with this BMP plan and any update hereto.
[Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: The preliminary BMP plan will be updated by SRF as the engineering of the Biomass Receiving, Handling, Storage and Processing emission unit (EU-001) is finalized. The final BMP plan must be submitted to the Compliance Authority no later than 180 days before the SRF facility becomes operational.}

Practice	Description
Best Management Practice – Minimization of Fugitive Dust	1) Conveyor systems and associated drop points shall be enclosed or partially enclosed. 2) Drop points to supplemental biomass storage areas shall be designed to minimize the overall exposed (or exposed to atmosphere) drop height. 3) Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed. 4) When required to meet the opacity standard for the Biomass Material Handling and Preparation emission unit, dust collector shall be installed at all biomass drop and transfer points. 5) All silos shall be equipped with vent filters. 6) Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities. 7) Plant personnel shall be trained on identification of warning signs for potential equipment malfunction. 8) Signs shall be posted identifying potential warning signs of equipment malfunction. 9) Procedures shall be established for defining excessive fugitive dust from biomass (sweet sorghum, wood chips, sweet sorghum residue and yard waste) truck unloading operations. Plant personnel shall visually observe truck unloading operations and if excessive fugitive dust is detected appropriate fugitive dust minimization techniques shall be implemented. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations. 10) All major roadways at the plant shall be paved. 11) Plant gravel areas shall be wetted during dry conditions, as required, to minimize fugitive dust emissions. 12) Mud, dirt or similar debris shall be removed promptly from the paved roads by vacuum sweeping. 13) Plant personnel shall be trained on what constitutes excessive dust on paved roads.
Storage Pile Management	1) Biomass (sweet sorghum, wood chips and yard waste) storage areas/piles shall be managed to avoid excessive wind erosion. 2) A biomass (sweet sorghum, wood chips and yard waste) fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs for conditions that could result in excessive fugitive dust formation. Plant personnel shall be trained on what warning signs to look for. 3) Mechanical moving of supplemental biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. 4) Objectionable odor is prohibited with first in first out supplemental biomass utilization implemented to minimize odors. 5) Daily visual observations of the supplemental biomass storage areas shall be performed and if conditions are right for fugitive dust formation, procedures from the fugitive dust plan shall be implemented.

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Best Management Practice – Fire Prevention /Spontaneous Combustion Minimization	1) Contact local fire marshal to develop fire management plan. Plan shall be maintained. 2) Fire Management plan to include: a) requirement to train onsite personnel to handle incipient fires and training on the identification of potential fire hazards; and, b) install and maintain equipment for plant personnel to handle incipient fires. The local fire department shall be invited to participate in onsite training. 3) Daily observations of the supplemental biomass storage areas shall be performed by plant personnel to identify potential fire hazards. Plant personnel shall be trained on identification of potential fire hazards. 4) Signs shall be posted at the plant, which identify potential fire hazards. 5) Incoming unprocessed supplemental biomass shall be stored in areas with a clearance between each storage area. 6) The reclaiming supplemental biomass shall be done to maximize the removal of older material in order to minimize the stacking of newer material on top of older material. 7) Compaction of supplemental biomass materials in the storage areas shall be minimized.
Best Management Practice – Quality Assurance of Biomass	1) The feedstock for the biomass boiler will consist of sweet sorghum bagasse and supplemental biomass (energy crops, wood chips and yard waste) that will be processed in designated areas. The primary biomass (sweet sorghum bagasse) will be sent directly to the biomass boiler. The excess bagasse and supplemental biomass will be placed in segregated storage areas and when required sent directly to the biomass boilers. 2) The permittee will contract for biomass that specifically meets the definition of clean wood chips and vegetable debris and bagasse as identified below: • Wood chips and vegetative debris will consist of clean untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), tree limbs (whole or chipped) and slash and yard waste. This also includes, but is not limited to, wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues. • Sorghum bagasse is the residue from the processing of sweet sorghum and cannot contain any other vegetative materials. 3) The permittee shall include within their contracts with suppliers a provision that limits the content of field residue (non-stalk parts such as plant leaves and tops) within deliveries of sorghum stalks to 5 percent by weight. 4) The permittee shall not obtain sorghum field residue for the purpose of use as a fuel for the biomass boiler at the SRF facility. 5) The supplemental biomass feedstock will be delivered to the SRF in vehicles designed to prevent release of fugitive dust. 6) For each shipment of biomass, the permittee shall record the date, quantity and a description of the material received. 7) The permittee shall inspect each shipment of biomass upon receipt for any material not specifically identified in this plan. If the permittee identifies any such material, the material shall be rejected and/or marshaled in specified areas until proper disposal can be arranged. Rejected materials shall be moved off site in a logistically reasonable time period. 8) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.

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Best Management Practice – Quality Assurance of Biomass	9) <u>Prohibited Materials</u>: The following items are not considered woody biomass and are expressly prohibited: a. those materials that are prohibited by state or federal law; b. plastics; c. woody biomass that has been chemically treated or processed; d. municipal solid waste other than yard trash per **Specific Condition 8** in **Subsection 3-A** of the permit and per §60.51b; e. paper; f. treated wood such as CCA or creosote; g. painted wood; and h. wood wastes from landfills.

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COMMON CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at SRF.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. 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.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. 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. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall 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. [Rule 62-296.320(1), F.A.C.]
7. 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.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

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RECORDS AND REPORTS

10. 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 5 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.]

11. Emissions Computation and Reporting

    a. *Applicability*. This rule sets forth required methodologies 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 this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

    b. *Computation of Emissions*. For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

        (1) 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.

            (a) 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.

            (b) 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.

            (c) 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.

        (2) Continuous Emissions Monitoring System (CEMS).

            (a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

                1) 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

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2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) 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:

1) A calibrated flowmeter that records data on a continuous basis, if available; or

2) 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.

(c) 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.

(3) Mass Balance Calculations.

(a) 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:

1) 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

2) 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.

(b) 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.

(c) 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.

(4) Emission Factors.

(a) 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.

1) 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.

2) 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.

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3) 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.

(b) 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.

(5) 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.

(6) 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.

(7) 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.

(8) 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.

c. Annual Operating Report for Air Pollutant Emitting Facility

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

(a) All Title V sources.

(b) All synthetic non-Title V sources.

(c) All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

(d) All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by April 1 of the following year.

(4) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

[Rule 62-210.370, F.A.C.]

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CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

CEMS OPERATION PLAN

1. CEMS Operation Plan: The owner or operator shall create and implement a facility-wide plan for the proper installation, calibration, maintenance and operation of each CEMS required by this permit. The owner or operator shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the owner or operator shall submit a new or revised plan for approval.

   {Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at (850)488-0114.}

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Timelines:

   a. *New and Existing Emission Units.* For new emission units, the owner or operator shall install each CEMS required by this permit prior to initial startup of the unit. The owner or operator shall conduct the appropriate performance specification for each CEMS within 90 operating days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup.

3. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR part 60, Appendix B.

4. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.

5. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR part 60, Appendix B, Performance Specification 6.

6. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach.

7. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

   {Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}

8. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit.

   a. *CO Monitors:* For CO monitors, the owner or operator shall conduct Performance Specification 4 or 4A of 40 CFR part 60, Appendix B

   b. *NO_X and SO_2 Monitors:* For NO_X and SO_2 monitors, the owner or operator shall conduct Performance Specification 2 of 40 CFR part 60, Appendix B.

   c. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15. Quality assurance procedures shall conform to the requirements of 40 CFR 60,

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Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority.

d. *COMS*: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

9. Quality Assurance: The owner or operator shall follow the quality assurance procedures of 40 CFR part 60, Appendix F.

a. *CO Monitors:* The required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR part 60 and shall be based on a continuous sampling train.

b. *NO_X Monitors:* The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR part 60. NO_X shall be expressed "as NO_2."

c. *SO_2 Monitors:* The required RATA tests shall be performed using EPA Method 6C in Appendix A of 40 CFR part 60.

d. *HCl CEMS*: The RATA tests required for the HCl monitor shall be performed using EPA Method 26 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

10. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

CALCULATION APPROACH

11. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.

12. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per **Condition 19** of this appendix.

13. Operating Hours and Operating Days: For purposes of this appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

14. Valid Hourly Averages*:* Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

a. Hours that are not operating hours are not valid hours.

b. For each operating hour, the 1-hour block 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, there is

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insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

    b. *Rolling 12-month Average*: Compliance shall be determined after each operating month by calculating the arithmetic average of all the valid hourly averages in that month and then calculating the arithmetic average of that operating month with the preceding 11 operating month averages in units of tons per year.

MONITOR AVAILABILITY

16. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required 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.

EXCESS EMISSIONS

17. Definitions:

    a. *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* means the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* means 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.

18. 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.

19. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition and **Specific Condition 13 of Subsection 3 B** of this permit, limited amounts of CEMS and COMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The data exclusion procedures of this condition apply only to SIP-based emission limits.

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

20. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. For malfunctions, notification is sufficient for the owner or operator to exclude CEMS data.

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ANNUAL EMISSIONS

21. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 12 of this appendix, shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit or RAA. These periods of time shall be considered missing data for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.

22. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block 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 owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.

23. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

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CITATION FORMATS AND GLOSSARY OF COMMON TERMS

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

Example: Permit No. AC50-123456 or 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 for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of 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 number

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 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

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

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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 (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

F: 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 with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

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 (control system used for reducing emissions of nitrogen oxides)

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

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COMMON TESTING REQUIREMENTS

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

COMPLIANCE TESTING REQUIREMENTS

1. 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.]

2. Applicable Test Procedures - 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.

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

3. 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.]

4. 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*.

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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. 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,
3. 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 visible emissions, if there is an applicable standard.
4. 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.

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.

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

RECORDS AND REPORTS

5. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the following information.
   a. The type, location, and designation of the emissions unit tested.
   b. The facility at which the emissions unit is located.
   c. The owner or operator of the emissions unit.
   d. 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.
   e. 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.
   f. The date, starting time and end time of the observation.
   g. The test procedures used.
   h. The names of individuals who furnished the process variable data, conducted the test, and prepared the

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report.

i. 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.

j. A certification that to the knowledge of the owner or his authorized agent, all data submitted are true and correct. 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.]

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NSPS, 40 CFR 60, SUBPART Db – STANDARDS OF PERFORMANCE SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

{Permitting Note: This is a modified version of NSPS, Subpart Db that retains the information applicable to the SRF project. Parts that are critical to the SRF project are provided in "Bold" text. To access the full version of NSPS, Subpart Db, follow the link at the end of this appendix.}

Subpart Db—Standards of Performance for 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 100 million British thermal units per hour (MMBtu/hr).

(b) Through (f) are not applicable (NA).

(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) Through (k) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 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.

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) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (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.

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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.

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 a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

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 or to enhance the performance of the unit (*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 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.

Low heat release rate means a heat release rate of 70,000 Btu/hr-ft^3 or less.

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

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); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

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Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (lb/mmBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (lb/mmBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any 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 after February 28, 2005 and not located in a noncontinental area, oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 0.32 lb/mmBtu heat input.

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.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) through (d) are NA.

(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) NA.

(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) through (j) are NA.

(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_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid

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waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) N/A

(3) NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.43b Standard for particulate matter (PM).

(a) through (d) are NA.

(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 can combust 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.** Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/mmBtu or less are exempt from the opacity standard specified in this paragraph.

(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), (h)(5), and (h)(6) 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 0.030 lb/mmBtu heat input,

(2) NA due to election by applicant to comply with (h)(1) above.

(3) Through (6) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.44b Standard for nitrogen oxides (NO_X).

(a) NA except for subsequent reference to the following table:

Fuel/steam generating unit type	**Nitrogen oxide emission limits (expressed as NO_2) (lb/mmBtu heat input)**
(1) Natural gas and distillate oil:	
(i) Low heat release rate	0.10

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(ii) High heat release rate	**0.20**

(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:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{no}H_{no}) + (EL_cH_c)}{(H_{go} + H_{no} + H_c)}$$

Where:

E_n= NO_X emission limit (expressed as NO_2), lb/mmBtu;

EL_{go}= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, lb/mmBtu;

H_{go}= Heat input from combustion of natural gas or distillate oil, 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 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) through (g) are NA.

(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) and (k) are NA.

(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:

a. If the affected facility combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 0.20 lb/mmBtu heat input unless the affected facility

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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

b. 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.

c. 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 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.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) NA.

(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) Through (j) NA.

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 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.

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(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 3A or 3B of appendix A–2 of this part is used for gas analysis when applying Method 5 of appendix A–3 of this part or Method 17 of appendix A–6 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–6 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 (320 °F).

(iii) NA.

(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_2sample 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) NA.

(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 250 mmBtu/hr and that combusts natural gas,

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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 250 mmBtu/hr or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §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) NA.

(f) through (i) are NA.

(j) NA unless applicant elects to install, calibrate and operate a PM-CEMS.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$and either O_2or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified SO_2 and O_2or 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_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) NA.

(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

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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_2CEMS at the inlet to the SO_2control 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_2control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2span 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_2monitors and for $SO_2$and NO_X monitors with span values greater than or equal to 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.

(ii) For all required $CO_2$and O_2monitors 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_2monitoring 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

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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).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 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 continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. [The rest of this paragraph is NA because the applicant will install a COMS.

(1) through (3) are NA because the applicant will install a COMS.

(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 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 COMS shall be between 60 and 80 percent.

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(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) through (i) are NA.

(j) NA because applicant will install a COMS.

(k) NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 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

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(4) NA because the applicant is not using an emerging technology for SO2 control.

(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) NA because the applicant will demonstrate NO_X compliance by use of a CEMS

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) 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.

(2) NA.

(e) NA.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) NA because the applicant will use a COMS.

(2) NA because the applicant will use a COMS.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(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) (lb/mmBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (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;

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(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 in §60.43b(f) or to the operating parameter monitoring requirements in §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, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §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 (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; For an exceedance due to maintenance of the SO_2control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

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(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 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; 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;

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(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_2standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) 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) NA.

(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, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition

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of distillate oil and gaseous fuel meets the definition of natural gas 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, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were 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) through (u) are NA.

(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) and (y) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009]

Link to 40 CFR 60, Subpart Db

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NSPS, 40 CFR 60, SUBPART Eb – STANDARDS OF PERFORMANCE LARGE MUNICIPAL WASTE COMBUSTORS

{Permitting Note: This is a modified version of NSPS, Subpart Eb that retains the information applicable to the SRF project, specifically the boiler being a cofired combustor and its burning of yard waste. Parts that are critical to the SRF project are provided in "Bold" text. To access the full version of NSPS, Subpart Eb, follow the link at the end of this appendix.}

SUBPART Eb—STANDARDS OF PERFORMANCE FOR LARGE MUNICIPAL WASTE COMBUSTORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 20, 1994 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED AFTER JUNE 19, 1996

(a) The affected facility to which this subpart applies is each municipal waste combustor unit with a combustion capacity greater than 250 tons per day of municipal solid waste for which construction, modification, or reconstruction is commenced after September 20, 1994.

(b) Any waste combustion unit that is capable of combusting more than 250 tons per day of municipal solid waste and is subject to a federally enforceable permit limiting the maximum amount of municipal solid waste that may be combusted in the unit to less than or equal to 11 tons per day is not subject to this subpart if the owner or operator:

(1) Notifies EPA of an exemption claim;

(2) Provides a copy of the federally enforceable permit that limits the firing of municipal solid waste to less than 11 tons per day; and

(3) Keeps records of the amount of municipal solid waste fired on a daily basis.

(c) An affected facility to which this subpart applies is not subject to subpart E or Ea of this part.

(d) Physical or operational changes made to an existing municipal waste combustor unit primarily for the purpose of complying with emission guidelines under subpart Cb are not considered a modification or reconstruction and do not result in an existing municipal waste combustor unit becoming subject to this subpart.

(e) A qualifying small power production facility, as defined in section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy is not subject to this subpart if the owner or operator of the facility notifies EPA of this exemption and provides data documenting that the facility qualifies for this exemption.

(f) A qualifying cogeneration facility, as defined in section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)), that burns homogeneous waste (such as automotive tires or used oil, but not including refuse-derived fuel) for the production of electric energy and steam or forms of useful energy (such as heat) that are used for industrial, commercial, heating, or cooling purposes, is not subject to this subpart if the owner or operator of the facility notifies EPA of this exemption and provides data documenting that the facility qualifies for this exemption.

(g) Any unit combusting a single-item waste stream of tires is not subject to this subpart if the owner or operator of the unit:

(1) Notifies EPA of an exemption claim; and

(2) [Reserved]

(3) Provides data documenting that the unit qualifies for this exemption.

(h) Any unit required to have a permit under section 3005 of the Solid Waste Disposal Act is not subject to this subpart.

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(i) Any materials recovery facility (including primary or secondary smelters) that combusts waste for the primary purpose of recovering metals is not subject to this subpart.

(j) Any cofired combustor, as defined under §60.51b, that meets the capacity specifications in paragraph (a) of this section is not subject to this subpart if the owner or operator of the cofired combustor:

(1) Notifies EPA of an exemption claim;

(2) Provides a copy of the federally enforceable permit (specified in the definition of cofired combustor in this section); and

(3) Keeps a record on a calendar quarter basis of the weight of municipal solid waste combusted at the cofired combustor and the weight of all other fuels combusted at the cofired combustor.

(k) Air curtain incinerators, as defined under §60.51b, located at a plant that meet the capacity specifications in paragraph (a) of this section and that combust a fuel stream composed of 100 percent yard waste are exempt from all provisions of this subpart except the opacity limit under §60.56b, the testing procedures under §60.58b(l), and the reporting and recordkeeping provisions under §60.59b (e) and (i).

(l) Air curtain incinerators located at plants that meet the capacity specifications in paragraph (a) of this section combusting municipal solid waste other than yard waste are subject to all provisions of this subpart.

(m) Pyrolysis/combustion units that are an integrated part of a plastics/rubber recycling unit (as defined in §60.51b) are not subject to this subpart if the owner or operator of the plastics/rubber recycling unit keeps records of the weight of plastics, rubber, and/or rubber tires processed on a calendar quarter basis; the weight of chemical plant feedstocks and petroleum refinery feedstocks produced and marketed on a calendar quarter basis; and the name and address of the purchaser of the feedstocks. The combustion of gasoline, diesel fuel, jet fuel, fuel oils, residual oil, refinery gas, petroleum coke, liquefied petroleum gas, propane, or butane produced by chemical plants or petroleum refineries that use feedstocks produced by plastics/rubber recycling units are not subject to this subpart.

(n) The following authorities are retained by the Administrator of the U.S. EPA and are not transferred to a State:

(1) Approval of exemption claims in paragraphs (b), (e), (f), (g) and (j) of this section;

(2) Enforceability under Federal law of all Federally enforceable, as defined in §60.51b, limitations and conditions;

(3) Determination of compliance with the siting requirements as specified in §60.57b(a);

(4) Acceptance of relationship between carbon monoxide and oxygen as part of initial and annual performance tests as specified in §60.58b(b)(7);

(5) Approval of other monitoring systems used to obtain emissions data when data is not obtained by CEMS as specified in §60.58b(e)(14), (h)(12), (i)(11), and (n)(14), and (p)(11);

(6) Approval of a site-specific monitoring plan for the continuous emission monitoring system specified in "60.58b(n)(13) and (o) of this section or the continuous automated sampling system specified in §60.58b(p)(10) and (q) of this section;

(7) Approval of major alternatives to test methods;

(8) Approval of major alternatives to monitoring;

(9) Waiver of recordkeeping; and

(10) Performance test and data reduction waivers under "608(b).

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(o) This subpart shall become effective June 19, 1996.

(p) Cement kilns firing municipal solid waste are not subject to this subpart.

[60 FR 65419, Dec. 19, 1995, as amended at 62 FR 45120, 45125, Aug. 25, 1997; 71 FR 27335, May 10, 2006]

§ 60.51b Definitions.

Administrator means:

(1) For approved and effective State Section 111(d)/129 plans, the Director of the State air pollution control agency, or employee of the State air pollution control agency that is delegated the authority to perform the specified task;

(2) For Federal Section 111(d)/129 plans, the Administrator of the EPA, an employee of the EPA, the Director of the State air pollution control agency, or employee of the State air pollution control agency to whom the authority has been delegated by the Administrator of the EPA to perform the specified task; and

(3) For NSPS, the Administrator of the EPA, an employee of the EPA, the Director of the State air pollution control agency, or employee of the State air pollution control agency to whom the authority has been delegated by the Administrator of the EPA to perform the specified task.

Air curtain incinerator means an incinerator that operates by forcefully projecting a curtain of air across an open chamber or pit in which burning occurs. Incinerators of this type can be constructed above or below ground and with or without refractory walls and floor.

Batch municipal waste combustor means a municipal waste combustor unit designed so that it cannot combust municipal solid waste continuously 24 hours per day because the design does not allow waste to be fed to the unit or ash to be removed while combustion is occurring.

Bubbling fluidized bed combustor means a fluidized bed combustor in which the majority of the bed material remains in a fluidized state in the primary combustion zone.

Calendar quarter means a consecutive 3-month period (nonoverlapping) beginning on January 1, April 1, July 1, and October 1.

Calendar year means the period including 365 days starting January 1 and ending on December 31.

Chief facility operator means the person in direct charge and control of the operation of a municipal waste combustor and who is responsible for daily onsite supervision, technical direction, management, and overall performance of the facility.

Circulating fluidized bed combustor means a fluidized bed combustor in which the majority of the fluidized bed material is carried out of the primary combustion zone and is transported back to the primary zone through a recirculation loop.

Clean wood means untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), and tree limbs (whole or chipped). Clean wood does not include yard waste, which is defined elsewhere in this section, or construction, renovation, and demolition wastes (including but not limited to railroad ties and telephone poles), which are exempt from the definition of municipal solid waste in this section.

Cofired combustor means a unit combusting municipal solid waste with nonmunicipal solid waste fuel (e.g., coal, industrial process waste) and subject to a federally enforceable permit limiting the unit to combusting a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of municipal solid waste as measured on a calendar quarter basis.

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Continuous emission monitoring system means a monitoring system for continuously measuring the emissions of a pollutant from an affected facility.

Dioxin/furan means tetra- through octa- chlorinated dibenzo-p-dioxins and dibenzofurans.

EPA means the Administrator of the U.S. EPA or employee of the U.S. EPA who is delegated to perform the specified task.

Federally enforceable means all limitations and conditions that are enforceable by EPA including the requirements of 40 CFR part 60, 40 CFR part 61, and 40 CFR part 63, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

First calendar half means the period starting on January 1 and ending on June 30 in any year.

Four-hour block average or *4-hour block average* means the average of all hourly emission concentrations when the affected facility is operating and combusting municipal solid waste measured over 4-hour periods of time from 12:00 midnight to 4 a.m., 4 a.m. to 8 a.m., 8 a.m. to 12:00 noon, 12:00 noon to 4 p.m., 4 p.m. to 8 p.m., and 8 p.m. to 12:00 midnight.

Mass burn refractory municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a refractory wall furnace. Unless otherwise specified, this includes combustors with a cylindrical rotary refractory wall furnace.

Mass burn rotary waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a cylindrical rotary waterwall furnace or on a tumbling-tile grate.

Mass burn waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a waterwall furnace.

Materials separation plan means a plan that identifies both a goal and an approach to separate certain components of municipal solid waste for a given service area in order to make the separated materials available for recycling. A materials separation plan may include elements such as dropoff facilities, buy-back or deposit-return incentives, curbside pickup programs, or centralized mechanical separation systems. A materials separation plan may include different goals or approaches for different subareas in the service area, and may include no materials separation activities for certain subareas or, if warranted, an entire service area.

Maximum demonstrated municipal waste combustor unit load means the highest 4-hour arithmetic average municipal waste combustor unit load achieved during four consecutive hours during the most recent dioxin/furan performance test demonstrating compliance with the applicable limit for municipal waste combustor organics specified under §60.52b(c).

Maximum demonstrated particulate matter control device temperature means the highest 4-hour arithmetic average flue gas temperature measured at the particulate matter control device inlet during four consecutive hours during the most recent dioxin/furan performance test demonstrating compliance with the applicable limit for municipal waste combustor organics specified under §60.52b(c).

Modification or *modified municipal waste combustor unit* means a municipal waste combustor unit to which changes have been made after June 19, 1996 if the cumulative cost of the changes, over the life of the unit, exceed 50 percent of the original cost of construction and installation of the unit (not including the cost of any land purchased in connection with such construction or installation) updated to current costs; or any physical change in the municipal waste combustor unit or change in the method of operation of the municipal waste combustor unit increases the amount of any air pollutant emitted by the unit for which standards have been established under section 129 or section 111. Increases in the amount of any air pollutant emitted by the municipal waste combustor unit are determined at 100-percent physical load capability and downstream of all

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air pollution control devices, with no consideration given for load restrictions based on permits or other nonphysical operational restrictions.

Modular excess-air municipal waste combustor means a combustor that combusts municipal solid waste and that is not field-erected and has multiple combustion chambers, all of which are designed to operate at conditions with combustion air amounts in excess of theoretical air requirements.

Modular starved-air municipal waste combustor means a combustor that combusts municipal solid waste and that is not field-erected and has multiple combustion chambers in which the primary combustion chamber is designed to operate at substoichiometric conditions.

***Municipal solid waste* or *municipal-type solid waste* or *MSW* means household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, nonmanufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by nonmanufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include:**

(1) Yard waste;

(2) Refuse-derived fuel; and

(3) Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in §60.50b(g).

Municipal waste combustor, MWC, or *municipal waste combustor unit:* (1) Means any setting or equipment that combusts solid, liquid, or gasified municipal solid waste including, but not limited to, field-erected incinerators (with or without heat recovery), modular incinerators (starved-air or excess-air), boilers (i.e., steam generating units), furnaces (whether suspension-fired, grate-fired, mass-fired, air curtain incinerators, or fluidized bed-fired), and pyrolysis/combustion units. Municipal waste combustors do not include pyrolysis/combustion units located at a plastics/rubber recycling unit (as specified in §60.50b(m)). Municipal waste combustors do not include cement kilns firing municipal solid waste (as specified in §60.50b(p)). Municipal waste combustors do not include internal combustion engines, gas turbines, or other combustion devices that combust landfill gases collected by landfill gas collection systems.

(2) The boundaries of a municipal solid waste combustor are defined as follows. The municipal waste combustor unit includes, but is not limited to, the municipal solid waste fuel feed system, grate system, flue gas system, bottom ash system, and the combustor water system. The municipal waste combustor boundary starts at the municipal solid waste pit or hopper and extends through:

(i) The combustor flue gas system, which ends immediately following the heat recovery equipment or, if there is no heat recovery equipment, immediately following the combustion chamber,

(ii) The combustor bottom ash system, which ends at the truck loading station or similar ash handling equipment that transfer the ash to final disposal, including all ash handling systems that are connected to the bottom ash handling system; and

(iii) The combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater.

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(3) The municipal waste combustor unit does not include air pollution control equipment, the stack, water treatment equipment, or the turbine-generator set.

Municipal waste combustor acid gases means all acid gases emitted in the exhaust gases from municipal waste combustor units including, but not limited to, sulfur dioxide and hydrogen chloride gases.

Municipal waste combustor metals means metals and metal compounds emitted in the exhaust gases from municipal waste combustor units.

Municipal waste combustor organics means organic compounds emitted in the exhaust gases from municipal waste combustor units and includes tetra-through octa- chlorinated dibenzo-p-dioxins and dibenzofurans.

Municipal waste combustor plant means one or more affected facilities (as defined in §60.50b) at the same location.

Municipal waste combustor unit capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under §60.58b(j). Section 60.58b(j) includes procedures for determining municipal waste combustor unit capacity for continuous and batch feed municipal waste combustors.

Municipal waste combustor unit load means the steam load of the municipal waste combustor unit measured as specified in §60.58b(i)(6).

Particulate matter means total particulate matter emitted from municipal waste combustor units as measured by EPA Reference Method 5 (see §60.58b(c)).

Plastics/rubber recycling unit means an integrated processing unit where plastics, rubber, and/or rubber tires are the only feed materials (incidental contaminants may be included in the feed materials) and they are processed into a chemical plant feedstock or petroleum refinery feedstock, where the feedstock is marketed to and used by a chemical plant or petroleum refinery as input feedstock. The combined weight of the chemical plant feedstock and petroleum refinery feedstock produced by the plastics/rubber recycling unit on a calendar quarter basis shall be more than 70 percent of the combined weight of the plastics, rubber, and rubber tires processed by the plastics/rubber recycling unit on a calendar quarter basis. The plastics, rubber, and/or rubber tire feed materials to the plastics/rubber recycling unit may originate from the separation or diversion of plastics, rubber, or rubber tires from MSW or industrial solid waste, and may include manufacturing scraps, trimmings, and off-specification plastics, rubber, and rubber tire discards. The plastics, rubber, and rubber tire feed materials to the plastics/rubber recycling unit may contain incidental contaminants (e.g., paper labels on plastic bottles, metal rings on plastic bottle caps, etc.).

Potential hydrogen chloride emission concentration means the hydrogen chloride emission concentration that would occur from combustion of municipal solid waste in the absence of any emission controls for municipal waste combustor acid gases.

Potential mercury emission concentration means the mercury emission concentration that would occur from combustion of municipal solid waste in the absence of any mercury emissions control.

Potential sulfur dioxide emissions means the sulfur dioxide emission concentration that would occur from combustion of municipal solid waste in the absence of any emission controls for municipal waste combustor acid gases.

Pulverized coal/refuse-derived fuel mixed fuel-fired combustor means a combustor that fires coal and refuse-derived fuel simultaneously, in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the unit where it is fired in suspension. This includes both conventional pulverized coal and micropulverized coal.

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Pyrolysis/combustion unit means a unit that produces gases, liquids, or solids through the heating of municipal solid waste, and the gases, liquids, or solids produced are combusted and emissions vented to the atmosphere.

Reconstruction means rebuilding a municipal waste combustor unit for which the reconstruction commenced after June 19, 1996, and the cumulative costs of the construction over the life of the unit exceed 50 percent of the original cost of construction and installation of the unit (not including any cost of land purchased in connection with such construction or installation) updated to current costs (current dollars).

Refractory unit or *refractory wall furnace* means a combustion unit having no energy recovery (e.g., via a waterwall) in the furnace (i.e., radiant heat transfer section) of the combustor.

Refuse-derived fuel means a type of municipal solid waste produced by processing municipal solid waste through shredding and size classification. This includes all classes of refuse-derived fuel including low-density fluff refuse-derived fuel through densified refuse-derived fuel and pelletized refuse-derived fuel.

Refuse-derived fuel stoker means a steam generating unit that combusts refuse-derived fuel in a semisuspension firing mode using air-fed distributors.

Same location means the same or contiguous property that is under common ownership or control including properties that are separated only by a street, road, highway, or other public right-of-way. Common ownership or control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, subdivision, or any combination thereof including any municipality or other governmental unit, or any quasi-governmental authority (e.g., a public utility district or regional waste disposal authority).

Second calendar half means the period starting July 1 and ending on December 31 in any year.

Shift supervisor means the person who is in direct charge and control of the operation of a municipal waste combustor and who is responsible for onsite supervision, technical direction, management, and overall performance of the facility during an assigned shift.

Spreader stoker coal/refuse-derived fuel mixed fuel-fired combustor means a combustor that fires coal and refuse-derived fuel simultaneously, in which coal 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.

Standard conditions means a temperature of 20 °C and a pressure of 101.3 kilopascals.

Total mass dioxin/furan or *total mass* means the total mass of tetra- through octa- chlorinated dibenzo-p-dioxins and dibenzofurans, as determined using EPA Reference Method 23 and the procedures specified under §60.58b(g).

Tumbling-tile means a grate tile hinged at one end and attached to a ram at the other end. When the ram extends, the grate tile rotates around the hinged end.

Twenty-four hour daily average or *24-hour daily average* means either the arithmetic mean or geometric mean (as specified) of all hourly emission concentrations when the affected facility is operating and combusting municipal solid waste measured over a 24-hour period between 12:00 midnight and the following midnight.

Untreated lumber means wood or wood products that have been cut or shaped and include wet, air-dried, and kiln-dried wood products. Untreated lumber does not include wood products that have been painted, pigment-stained, or "pressure-treated." Pressure-treating compounds include, but are not limited to, chromate copper arsenate, pentachlorophenol, and creosote.

Waterwall furnace means a combustion unit having energy (heat) recovery in the furnace (i.e., radiant heat transfer section) of the combustor.

***Yard waste* means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance**

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activities associated with yards or other private or public lands. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of municipal solid waste in this section. Yard waste does not include clean wood, which is exempt from the definition of municipal solid waste in this section.

Link to Subpart Eb

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40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

{Permitting Note: This is the section (Section 5) of Appendix F of 40 CFR 75 including the F-Factor Table for fuels that deals with the calculation of the heat input rate to a steam generating boiler. This procedure is utilized by boilers that fall under the Acid Rain program. This is the procedure that SRF may utilize instead of the ASME procedure given in Appendix ASME to calculate the heat input rate to the biomass boiler. To access the full version of 40 CFR 75, Appendix F, follow the link at the end of this appendix.}

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in §75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO_2concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \qquad (Eq.\ F\text{-}15)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c= Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2w}$= Hourly concentration of CO_2during unit operation, percent CO_2wet basis.

5.2.2 When measurements of CO_2concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100F_c}\right]\left(\frac{\%CO_{2d}}{100}\right) \qquad (Eq.\ F\text{-}16)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c= Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$= Hourly concentration of CO_2during unit operation, percent CO_2dry basis.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_{2w}\right]}{20.9} \qquad (Eq.\ F\text{-}17)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

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$\%O_{2w}$= Hourly concentration of O_2during unit operation, percent O_2wet basis. For any operating hour where Equation F–17 results in an hourly heat input rate that is ≤ 0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100\ F}\right]\left[\frac{(20.9 - \%O_{2d})}{20.9}\right] \qquad (Eq.\ F\text{-}18)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in Table 1 at the end of this of this appendix for each fuel, dscf/mmBtu.

$\%H_2O$ = Moisture content of the stack gas, percent.

$\%O_{2d}$= Hourly concentration of O_2during unit operation, percent O_2dry basis.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i \qquad (Eq.\ F\text{-}18a)$$

Where:

HI_q= Total heat input for the quarter, mmBtu.

HI_i= Hourly heat input rate during unit operation, using Equation F–15, F–16, F–17, or F–18, mmBtu/hr.

t_i= Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \qquad (Eq.\ F\text{-}18b)$$

Where:

HI_c= Total heat input for the year to date, mmBtu.

HI_q= Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_X mass emissions under a State or federal NO_X mass emission reduction program.

5.5.1 (a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

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$$HI_o = M_o \frac{GCV_o}{10^6} \qquad (Eq.\ F\text{-}19)$$

Where:

HI_o= Hourly heat input rate from oil, mmBtu/hr.

M_o= Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o= Gross calorific value of oil, as measured by ASTM D240–00, ASTM D5865–01a, or ASTM D4809–00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under (§75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

(b) When performing oil sampling and analysis solely for the purpose of the missing data procedures in §75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6} \qquad (Eq.\ F\text{-}20)$$

Where:

HI_g= Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g= Metered flow rate of gaseous fuel combusted during unit operation, hundred standard cubic feet per hour.

GCV_g= Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under §75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1–5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under §75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234–00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under §75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in §75.36, use of ASTM D2234–00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under §75.6 of this part. Use ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis, for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§75.23 and 75.66.

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5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500} \qquad (Eq.\ F\text{-}21)$$

(Eq. F–21)

where:

HIc = Daily heat input from coal, mmBtu/day.

Mc = Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c= Gross calorific value of coal sample, as measured by ASTM D3176–89 (Reapproved 2002), or ASTM D5865–01a, Btu/lb. (incorporated by reference under §75.6 of this part).

500 = Conversion of Btu/lb to mmBtu/ton.

5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain HI_i for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F–21.

5.5.5 If a daily fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 30 daily samples. If a monthly fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 3 monthly samples.

5.5.6 If a fuel flow value is not available, use the fuel flowmeter missing data procedures in section 2.4 of appendix D of this part. If a daily coal consumption value is not available, substitute the maximum fuel feed rate during the previous thirty days when the unit burned coal.

5.5.7 Results for samples must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results be available in five business days, or sooner if practicable.

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{j=1}^{n} MW_j t_j}\right] \qquad (Eq.\ F\text{-}21a)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{cs}= Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i= Gross electrical output, MWe.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

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i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right] \qquad (Eq.\ \text{F-21b})$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CS}= Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr, or mmBtu/hr.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes shall sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}} \qquad (Eq.\ \text{F-21c})$$

Where:

HI_{Unit}= Heat input rate for a unit, mmBtu/hr.

HI_s= Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit}= Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s= Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

5.8 Alternate Heat Input Apportionment for Common Pipes

As an alternative to using Equation F–21a or F–21b in section 5.6 of this appendix, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

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40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad (Eq.\ \text{F-21}d)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CP}= Heat input rate at the common pipe, mmBtu/hr.

FF_i= Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CP}= Common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common pipe.

i = Designation of a particular unit.

3.3.5 F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels. The permittee at their discretion may use the procedure of 40 CFR Part 75, Appendix F, Section 3.3.6 to calculate a site specific F factor for the BFB biomass boiler at the GREC facility.

Table 1—F- and F_c-Factors[1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99[2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		

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Bark	9,600	1,920
Wood residue	9,240	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury. SRF may develop their own F factors for there fuels.

[2]Incorporated by reference under §75.6 of this part.

Link to 40 CFR 75, Appendix F

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GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

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NSPS SUBPART A AND NESHAP SUBPART A - IDENTIFICATION OF GENERAL PROVISIONS

NSPS - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

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§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

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NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

Two 2000 kW or less emergency generator (EU ID 009) and one 600 hp or less water pump (EU-010) are proposed for the SRF facility and they are subject to the applicable requirements of 40 CFR 60, Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart IIII

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NSPS, SUBPART KB – STANDARDS OF PERFORMANCE FOR VOLATILE ORGANIC LIQUID STORAGE VESSELS

Five blending and storage tanks, EU 006, at SRF are subject to NSPS Subpart Kb which applies to any storage tank with a capacity greater than or equal to 10,300 gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. Four of these tanks have a capacity greater than or equal to 40,000 gallons while the gasoline storage tank has a capacity of 28,467 gallons. All five tanks store a liquid with a maximum true vapor pressure greater than 3.5 kilopascals (kPa). Consequently, all five tanks are subject to the General Provisions (40 CFR 60, Subpart A) and the provisions of NSPS 40 CFR 60, Subpart Kb.

Link to Subpart Kb

Link to Subpart A

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PRELIMINARY LEAK DETECTION AND REPAIR (LDAR) PROGRAM

The applicant provided the following LDAR program developed pursuant to Subpart VVa. The applicant shall provide a more comprehensive version for the SRF facility to the Compliance Authority no later than 90 days before the SRF becomes operational. The LDAR program applies to EU 011 at SRF.

Leak Detection and Repair (LDAR) Program

Southeast Renewable Fuels, LLC (SRF) will be subject to the new source performance standards (NSPS) contained in Title 40, Part 60 of the Code of Federal Regulations (40 CFR 60), Subpart VVa – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. This subpart applies to all process units within the Synthetic Organic Chemicals Manufacturing Industry (SOCMI). The SOCMI industry is defined as the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489. Ethanol is one of those listed chemicals.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in §60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels [except as specified in §60.482-1a(g)], product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in Subpart VVa (i.e., pumps, compressors, pressure relief devices, sampling connections, open-ended valves or lines, valves, valves, and connectors).

The following preliminary LDAR program was developed for the Southeast Renewable Fuels facility pursuant to Subpart VVa.

Leak Detection and Repair (LDAR) Program

1. PURPOSE

The objective of this procedure is to establish guidelines for implementing and managing a Leak Detection and Repair (LDAR) program at the SRF facility located near Clewiston, Florida. The use of this procedure will assure compliance with federal and state regulations.

2. SCOPE

The provisions of this Subpart VVa apply to affected facilities in the synthetic organic chemicals manufacturing industry. In the case of the SRF facility, the affected facility is the process equipment that produces ethanol. The group of all equipment (defined in §60.481a) within a process unit is an affected facility. This LDAR procedure applies to all regulated components within a process unit which are in volatile organic compound (VOC) service at the SRF facility. A "Process unit" for purposes of Subpart VVa means the following:

the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in §60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482-1a(g)), product transfer racks, and connected ducts and piping.

"Storage vessel" under Subpart VVa is defined as follows:

A tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

"In VOC service" means:

The piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.

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PRELIMINARY LEAK DETECTION AND REPAIR (LDAR) PROGRAM

The preliminary applicability of Subpart VVa to each emissions unit at the SRF facility is presented below:

EU-001: Biomass Material Handling and Preparation

- Not Applicable- contains no fluids or no fluids in VOC service

EU-002: Cogeneration Biomass Boiler

- Applicable only to the closed vent system routing the biogas to the boiler

EU-003: Cooling Towers

- Not Applicable- contains no fluids in VOC service

EU-004: Ethanol Production Process

- Applicable

EU-005: Bioreactors and Biogas Flare

- Applicable to bioreactors and closed vent system to flare and to biomass boiler

EU-006: Storage Tanks

- Applicable to tanks in ethanol process and storage tanks that are in VOC service

EU-007: Truck Rack Product Loadout and Flare.

- Applicable

EU-008: Miscellaneous Storage Silos

- Not Applicable- contains no fluids or no fluids in VOC service

EU-009: Two Emergency Generators

- Not Applicable- not part of ethanol production process

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EU-010: Emergency Diesel Fueled Fire Pump Engine

- Not Applicable- not part of ethanol production process

EU-011: Facility-Wide Fugitive VOC Emission Leaks

- Only applicable as identified above for each emissions unit.

3. LDAR PROGRAM

a. Identification of Components
   - Each regulated equipment/component in VOC service will be identified on a site plot plan or on a continuously updated equipment log.
   - A unique identification (ID) number will be assigned to each regulated component.
   - Purchase tags and physically locate each regulated component in the facility, verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams, and tag each component. Update the equipment log if necessary.
   - Record each regulated component and its unique ID number in a log.
   - • Promptly note in the equipment log when new and replacement pieces of equipment are added and equipment is taken out of service.

b. Leak Definition
   - The leak definition/criteria for each regulated component will be identified. The definition of a "leak" varies by regulation, equipment type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Certain equipment leak requirements define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around components), sound (such as hissing), and smell.

c. Monitoring Components
   - The monitoring intervals for each regulated equipment/component will be identified. Monitoring intervals vary according to the equipment/component type, i.e., weekly, monthly, quarterly, or annually.
   - • Monitor all regulated components in accordance with EPA Method 21 (40 CFR Part 60 Appendix A) at the intervals specified. Obtain background readings from regulated equipment designated as no detectable emissions: perform initially, annually, and when requested by FDEP.

d. Repairing Components
   - All leaking components will be repaired as soon as practicable, but no later than five days for first attempt at repair and 15 days for final attempt at repair.
   - Perform follow-up monitoring of the repaired component to ensure the component is not "leaking".
   - Place all leaking components that would require a process unit shutdown on the Delayed Repair List. Record the component ID number and an explanation of why the component cannot be repaired immediately. Also include an estimated date for repairing the equipment.

e. Recordkeeping
   - Maintain a list of all ID numbers for all equipment/components subject to the LDAR program.
   - For valves designated as "unsafe to monitor", maintain a list of ID numbers and an explanation/review of conditions for the designation.
   - Maintain detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams.

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- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring leak-less equipment, and non-periodic event monitoring.
  - Attach ID tags to all leaking equipment.
  - Maintain records of the equipment/component ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a list of the dates of each repair attempt and an explanation of the attempted repair method.
- Maintain a list of the dates of successful repairs and include the results of monitoring test to determine the leak was repaired successfully.

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NSPS SUBPART VVA – STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC IN THE SOCMI

The most practical method of controlling fugitive VOC emissions from SRF is to promptly repair any leaking components. SRF is subject to NSPS 40 CFR 60, Subpart VVa - VOC Equipment Leaks in the Synthetic Chemical Manufacturing Industry (SOCMI), for projects that commence construction or modifications after November 7, 2006. NSPS Subpart VVa requires a LDAR program. SRF must come in to compliance with Subpart VVa, including the LDAR program, no later than 180 days after SRF becomes operational.

SUBPART VVa—STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in §60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in §60.489 is exempt from §§60.482–1a through 60.482–11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§60.482–1a through 60.482–11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§60.482–1a through 60.482–11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§60.482–1a through 60.482–11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of §60.485a(d), (e), and (f), and §60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All

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sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

(f) *Stay of standards.* (1) Owners or operators that start a new, reconstructed, or modified affected source prior to November 16, 2007 are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the Federal Register.

(i) The definition of "capital expenditure" in §60.481a of this subpart. While the definition of "capital expenditure" is stayed, owners or operators should use the definition found in §60.481 of subpart VV of this part.

(ii) [Reserved]

(2) Owners or operators are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the Federal Register.

(i) The definition of "process unit" in §60.481a of this subpart. While the definition of "process unit" is stayed, owners or operators should use the following definition:

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in §60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

(ii) The method of allocation of shared storage vessels in §60.482–1a(g) of this subpart.

(iii) The standards for connectors in gas/vapor service and in light liquid service in §60.482–11a of this subpart.

[72 FR 64883, Nov. 16, 2007, as amended at 73 FR 31375, June 2, 2008]

§ 60.481A DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	Value of B to be used in equation

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VVa	12.5
GGGa	7.0

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007–2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e).

In-situ sampling systems means nonextractive samplers or in-line samplers.

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In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of §60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

Initial calibration value means the concentration measured during the initial calibration at the beginning of each day required in §60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in §60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§60.482–2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482–3a(f), and 60.482–10a(f)(1)(ii), is re-monitored as specified in §60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

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Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in §60.2 Definitions.

Effective Date Note: At 73 FR 31376, June 2, 2008, in §60.481a, the definitions of "capital expenditure" and "process unit" were stayed until further notice.

§ 60.482-1A STANDARDS: GENERAL.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482–1a to 60.482–10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, and 60.482–10a as provided in §60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, or 60.482–10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482–2a through 60.482–10a if it is identified as required in §60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§60.482–2a through 60.482–11a if it is identified as required in §60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§60.482–2a, 60.482–7a, and 60.483.2a:

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Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	**Quarterly**	**Semiannually**
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

Effective Date Note: At 73 FR 31376, June 2, 2008, in §60.482–1a, paragraph (g) was stayed until further notice.

§ 60.482-2A STANDARDS: PUMPS IN LIGHT LIQUID SERVICE.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482–1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482–1a(c) and paragraphs (d), (e), and (f) of this section.

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(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482–1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

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(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482–10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482-3A STANDARDS: COMPRESSORS.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482–1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

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(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482–10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4A STANDARDS: PRESSURE RELIEF DEVICES IN GAS/VAPOR SERVICE.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482–9a.

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(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482–10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482–9a.

§ 60.482-5A STANDARDS: SAMPLING CONNECTION SYSTEMS.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482–1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482–10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

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(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6A STANDARDS: OPEN-ENDED VALVES OR LINES.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7A STANDARDS: VALVES IN GAS/VAPOR SERVICE AND IN LIGHT LIQUID SERVICE.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c) and (f), and §§60.483–1a and 60.483–2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c), and §§60.483–1a and 60.483–2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with §60.483–1a or §60.483–2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483–2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

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(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

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NSPS SUBPART VVA – STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC IN THE SOCMI

§ 60.482-8A STANDARDS: PUMPS, VALVES, AND CONNECTORS IN HEAVY LIQUID SERVICE AND PRESSURE RELIEF DEVICES IN LIGHT LIQUID OR HEAVY LIQUID SERVICE.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§60.482–2a(c)(2) and 60.482–7a(e).

§ 60.482-9A STANDARDS: DELAY OF REPAIR.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482–10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

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§ 60.482-10A STANDARDS: CLOSED VENT SYSTEMS AND CONTROL DEVICES.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices 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.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual inspections according to the procedures in §60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

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(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).

(4) For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.482-11A STANDARDS: CONNECTORS IN GAS/VAPOR SERVICE AND IN LIGHT LIQUID SERVICE.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in §60.482–1a(c), §60.482–10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results

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from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$= Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L= Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t= Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

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(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors* . (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

Effective Date Note: At 73 FR 31376, June 2, 2008, §60.482–11a was stayed until further notice.

§ 60.483-1A ALTERNATIVE STANDARDS FOR VALVES—ALLOWABLE PERCENTAGE OF VALVES LEAKING.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

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(3) If a valve leak is detected, it shall be repaired in accordance with §60.482–7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

§ 60.483-2A ALTERNATIVE STANDARDS FOR VALVES—SKIP PERIOD LEAK DETECTION AND REPAIR.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482–7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482–7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in §60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482–7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484A EQUIVALENCE OF MEANS OF EMISSION LIMITATION.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

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(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

§ 60.485A TEST METHODS AND PROCEDURES.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482–1a through 60.482–11a, 60.483a, and 60.484a as follows:

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(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, 60.482–7a(f), and 60.482–10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A–7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

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(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A–7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$V_{max} = K_1 + K_2 H_T$

Where:

V_{max}= Maximum permitted velocity, m/sec (ft/sec).

H_T= Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1= 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2= 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

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

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i= Concentration of sample component "i," ppm

H_i= net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A–6 of this part or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference-see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382–76 or 88 or D4809–95 (incorporated by reference-see §60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A–7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

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(h) The owner or operator shall determine compliance with §60.483–1a or §60.483–2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$\%V_L = (V_L / V_T) * 100$

Where:

$\%V_L$= Percent leaking valves.

V_L= Number of valves found leaking.

V_T= The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with §60.482–7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486A RECORDKEEPING REQUIREMENTS.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482–7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in §60.482–11a(b)(3)(iv) and no leak has been detected during that monitoring.

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(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A–7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482–10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482–10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482–1a to 60.482–11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482–2a(e), 60.482–3a(i), and 60.482–7a(f).

(ii) The designation of equipment as subject to the requirements of §60.482–2a(e), §60.482–3a(i), or §60.482–7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482–4a.

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(4)(i) The dates of each compliance test as required in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, and 60.482–7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482–1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A–7 of this part and §60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A–7 of this part.

(v) Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in §60.482–11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to §60.482–4a.

(f) The following information pertaining to all valves subject to the requirements of §60.482–7a(g) and (h), all pumps subject to the requirements of §60.482–2a(g), and all connectors subject to the requirements of §60.482–11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483–2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482–2a(d)(5) and 60.482–3a(e)(2) and explanation of the design criterion; and

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(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487A REPORTING REQUIREMENTS.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482–7a, excluding those valves designated for no detectable emissions under the provisions of §60.482–7a(f).

(3) Number of pumps subject to the requirements of §60.482–2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482–2a(e) and those pumps complying with §60.482–2a(f).

(4) Number of compressors subject to the requirements of §60.482–3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482–3a(i) and those compressors complying with §60.482–3a(h).

(5) Number of connectors subject to the requirements of §60.482–11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482–7a(b) or §60.483–2a,

(ii) Number of valves for which leaks were not repaired as required in §60.482–7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482–2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in §60.482–2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in §60.482–3a(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482–3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in §60.482–11a(b)

(viii) Number of connectors for which leaks were not repaired as required in §60.482–11a(d), and

(ix)–(x) [Reserved]

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(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483–1a or 60.483–2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

§ 60.488A RECONSTRUCTION.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under §60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in §60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489A LIST OF CHEMICALS PRODUCED BY AFFECTED FACILITIES.

Process units that produce, as intermediates or final products, chemicals listed in §60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006

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NESHAP, SUBPART ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

Two 2000 kW or less emergency generators (EU ID 009) and one 600 hp or less fire water pump engine (EU-010) are proposed for the SRF facility and they are subject to the requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

Link to Subpart ZZZZ

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